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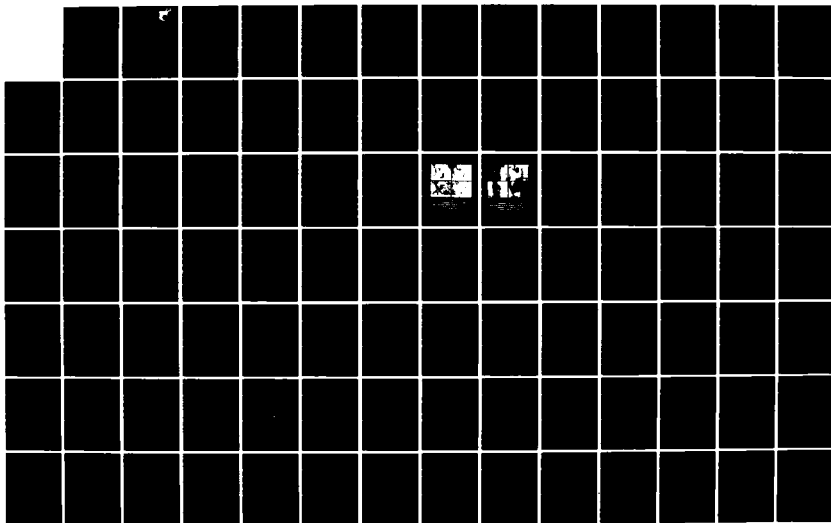
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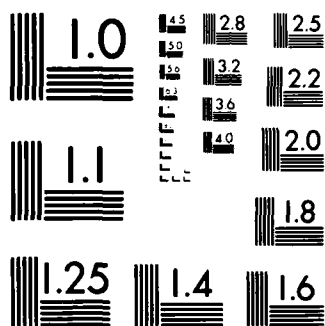
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Volume II. Phases III and IV

UOP INC.  
ALGONQUIN AND MT. PROSPECT ROADS  
DES PLAINES, ILLINOIS 60016

JULY 1982

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AIR FORCE WRIGHT AERONAUTICAL LABORATORIES  
AIR FORCE SYSTEMS COMMAND  
WRIGHT-PATTERSON AFB, OH 45433

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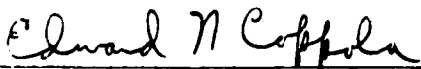
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This technical report has been reviewed and is approved for publication.



EDWARD N. COPPOLA, 1LT, USAF  
Fuels Branch, Fuels and Lubrication Division  
Aero Propulsion Laboratory



ARTHUR V. CHURCHILL  
Chief, Fuels Branch  
Fuels and Lubrication Division  
Aero Propulsion Laboratory



ROBERT D. SHERRILL  
Chief, Fuels and Lubrication Division  
Aero Propulsion Laboratory

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20. ABSTRACT (Continue on reverse side if necessary and identify by block number) The overall objective of this project was to demonstrate innovative technology to reduce the cost of converting shale oil to high yields of aviation turbine fuels. To carry out this program, UOP selected a processing scheme involving two stages of hydrotreating followed by hydrocracking. The Phase III and IV programs included first-stage hydrotreating catalyst stability testing; the production of jet and diesel fuel samples using the hydrocracking process; naphtha hydrotreating and catalytic reforming; arsenic management studies; an investigation of shale oil fouling; a shale oil/petroleum stability/compatibility study; and an economic analysis of the proposed upgrading scheme.		

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The novel hydrocracking scheme was successful in producing high quality jet fuel samples. A comparison of some key product properties with the specifications shows:

	JP-4		JP-8	
	Spec.	Product	Spec.	Product
Sp. Gr. 60/60°F	0.751-0.802	0.7813	0.775-0.840	0.7972
Smoke Point	20	28.5	25	27.2
Aromatics, vol-%	25	8.7	25	9.3
Combustion, Btu/lb.	18,400	18,700	18,400	18,600

Based on yields and operating conditions demonstrated in pilot plant operations, process designs were prepared for the first- and second-stage hydrotreaters and the hydrocracker. These designs along with the information for the other process units were incorporated into a linear program model for a shale oil refinery. Using the basis provided by the USAF and assuming 100,000 barrels per stream day (BPSD) of raw shale oil valued at \$40/B, the following results were obtained:

	Max. JP-4	Max. JP-8
Jet Fuel Yield, BPSD	91,760	80,742
Total Liquid Product Yield	91,760	89,591
Capital Investment, MM \$	902	939
Product Cost, \$/B of Total Liquid Product	56.82	58.80

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# FOREWORD

The final report describes the work completed by UOP Inc. on Phases III and IV of the Contract No. F33615-78-C-2079 entitled "United States Air Force Shale Oil to Fuels."

First Lieutenant Edward N. Coppola was the project engineer for the Air Force Wright Aeronautical Laboratories.

The work reported herein was performed during the period 1 October 1980 - 31 December 1981 under the direction of A. O. Braun and J. R. Wilcox. This report was submitted to the USAF in April, 1982.

The following individuals contributed to the execution of the program and the preparation of the report material:

Lee Hilfman, E. J. Latos, and J. G. Gatsis; all of the Corporate Research Center, UOP Inc.;  
J. G. Sikonia, T. G. Board, V. A. Gembicki, J. R. Wilcox and Edwin Yuh; all of the Process Division of UOP Inc.

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# LIST OF SYMBOLS

## Symbols

A	Aromatics in FIA Analysis
AAS	Atomic Absorption Spectroscopy
B	Barrel
BFW	Boiler Feed Water
BPCD	Barrels per Calendar Day
BPSD	Barrels per Stream Day
Btu/lb	British Thermal Units per Pound
BTX	Benzene, Toluene, Xylene
°C	Degrees Celsius
C	Combined Feed Ratio
C <sub>B</sub>	Combined Feed Ratio of Base Operation
CFR	Combined Feed Ratio, Vol. Feed Rate/(Feed Rate + Recycle Rate)
cSt	Centistoke
DCF	Discounted Cash Flow
dR <sub>F</sub> /dt	Fouling Rate
EEC	Estimated Erected Cost
EFCEST	Engineering for Cost Estimating
EP	End Point of Distillation
EPA	U.S. Environmental Protection Agency
°F	Degrees Fahrenheit
FIA	Fluorescent-Indicator Adsorption
gal	Gallon
GC	Gas Chromatograph
h	Heat Transfer Coefficient
H	H <sub>2</sub> Recycle Ratio in SCFB
H <sub>B</sub>	H <sub>2</sub> Recycle Ratio of Base Operation
HP	High Pressure (Steam)
K	Degrees Kelvin
kWh	Kilowatt Hour
L	Liquid Hourly Space Velocity, LHSV
L <sub>B</sub>	LHSV of Base Operation
LHSV	Liquid Hourly Space Velocity
LP	Low Pressure (Steam)
LP	Linear Programming
MON	Motor Octane Number
mL	Milliliter
MM \$	Millions of U.S. Dollars
MP	Medium Pressure (Steam)

# LIST OF SYMBOLS

## Symbols

N	Naphthenes in FIA Analysis
O	Olefins in FIA Analysis
P	Paraffins in FIA Analysis
P	Pressure
P <sub>B</sub>	Pressure of Base Operation
ppm	Parts per Million
psig	Pressure, Pounds per Square Inch Gauge
Q	Heat Input
R <sub>F</sub>	Fouling Factor
RON	Research Octane Number
RONC	Research Octane Number Clear (no lead addition)
R+M/2	Average of Research and Motor Octane Numbers
RVP	Reid Vapor Pressure
SCFB	Standard Cubic Feet per Barrel
SCFD	Standard Cubic Feet per Day
SEM	Scanning Electron Microscope
Sp. Gr.	Specific Gravity
ST/D	Short Tons per Day
SUS	Saybolt Universal Seconds
T	Temperature
T <sub>B</sub>	Temperature of Base Operation
TEL	Tetra-ethyl Lead
T <sub>F</sub>	Fluid Temperature
T <sub>W</sub>	Wire Temperature
vol-%	Volume Percent
wt-%	Weight Percent

## SUMMARY

The overall objective of this project was to demonstrate innovative technology to reduce the cost of converting shale oil to high yields of aviation turbine fuels. To carry out this program, UOP selected a processing scheme involving two stages of hydrotreating followed by hydrocracking. The Phase III and IV programs included first-stage hydrotreating catalyst stability testing, the production of jet and diesel fuel samples using the hydrocracking process, naphtha hydrotreating and catalytic reforming, arsenic management studies, an investigation of shale oil fouling, a shale oil/petroleum stability/compatibility study, and an economic analysis of the proposed upgrading scheme.

Based on the results of a six-month, first-stage hydrotreating operation, it was concluded that the catalyst showed excellent stability for arsenic and iron removal, and that high concentrations of contaminants could be contained. Fouling noted in the pilot plant preheater must be considered in a commercial design.

The novel hydrocracking scheme was successful in producing high quality jet fuel samples. A comparison of some key product properties with the specifications shows:

	JP-4		JP-8	
	Spec.	Product	Spec.	Product
Sp. Gr. 60/60°F	0.751-0.802	0.7813	0.775-0.840	0.7972
Smoke Point	20	28.5	25	27.2
Aromatics, vol-%	25	8.7	25	9.3
Combustion, Btu/lb	18,400	18,700	18,400	18,600

Catalytic reforming of the naphtha produced in the hydrocracking operation showed this material to be comparable to petroleum feedstocks and give C<sub>5</sub> plus liquid yields of 85 and 70 vol-% at 89 and 104 Research octane numbers (clear), respectively.

The aqueous solubility of arsenic on the used hydrotreating catalyst was found to exceed the acceptable level in the EPA Toxicity test. The arsenic-containing species were identified, thermal and chemical passivation and extraction techniques were investigated, and recommendations for further work were formulated.

Fouling studies showed that freshly produced samples would probably be much more reactive than the samples tested and that hydrotreating decreases the fouling tendency. A study of the compatibility and stability of blends of shale oils and petroleum showed no serious problems.

Based on yields and operating conditions demonstrated in pilot plant operations, process designs were prepared for the first- and second-stage hydrotreaters and the hydrocracker. These designs along with the information for the other process units were incorporated into a linear program

model for a shale oil refinery. Using the basis provided by the USAF and assuming 100,000 barrels per stream day (BPSD) of raw shale oil valued at \$40/B, the following results were obtained:

	<u>Max. JP-4</u>	<u>Max. JP-8</u>
Jet Fuel Yield, BPSD	91,760	80,742
Total Liquid Product Yield	91,760	89,591
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Product Cost, \$/B of Total Liquid Product	56.82	58.80

## SECTION I

### INTRODUCTION

This study was conducted to develop yield and economic data for the conversion of shale oil to aviation turbine fuels using innovative processing techniques. A processing scheme maximizing the yield of jet fuels at minimum cost was developed during Phase I of this program. This scheme consisted of the primary shale oil upgrading and conversion units with the necessary auxiliary facilities. The primary units include two stages of upgrading utilizing proprietary RCD Unibon® technology combined with UOP Hydrotreating technology. The upgraded shale oil is then converted to high yields of jet fuel using a novel, "parallel-flow" hydrocracking operation included in the UOP proprietary HC Unibon® technology.

The UOP approach to the problem of shale oil conversion to high quality fuels involves three distinct hydroprocessing steps. Shale oil has unique characteristics relative to conventional crude petroleum oil. Unusually high arsenic and iron levels, high pour point and viscosity, a high unsaturates concentration, and a significant solids (ash) content make conventional front-end refining techniques unusable without proper pretreatment.

The initial step in the UOP scheme is a feed preparation procedure which is essentially a desalting operation. The pilot plant utilized for this operation is completely analogous to a two-stage desalting unit commonly used in the refining industry.

After desalting, the first hydroprocessing step involves the use of UOP's RCD Unibon technology to effect metals removal, sulfur reduction, a degree of diolefin and olefin saturation, and the final solids clean-up necessary to render the resulting effluent suitable for subsequent processing.

Another characteristic of shale oil is its high nitrogen content relative to conventional crude oil. Reducing this contaminant to acceptable levels requires the use of a second-stage, high severity hydrotreatment of the first-stage hydrotreater effluent.

Once the metals, other contaminants and nitrogen contents have been reduced to acceptable levels and the unsaturates hydrogenated, shale oil is ready for the primary conversion step -- hydrocracking to jet and other fuels. The hydrocracking process that UOP has selected is a parallel-flow hydrocracker developed for conventional petroleum use.

Although jet fuel is the primary product in the overall refinery developed by UOP, diesel fuel and naphtha can also be produced. The naphtha was split into light and heavy fractions, with the heavy fraction converted to a gasoline component by reforming via a UOP Platforming® process unit. The reformate was mixed with the light naphtha fraction and sufficient butanes to produce the finished gasoline.

Phase I of the program provided for the development of innovative processing techniques and associated information for the conversion of shale oil to high yields of jet fuel. Phase II was primarily a test program utilizing small scale pilot plants to demonstrate the processing techniques developed in Phase I. The following summarizes the specific objectives for Phase II:

- Characterization of feedstock
- Determination of the shale oil fouling characteristics
- Preparation of sufficient feedstock to explore parallel-flow hydrocracking operating parameters
- Exploration of first- and second-stage hydrotreating operating parameters and catalyst systems
- Production of small scale jet fuel product samples

- Verification and/or adjustment of the operating requirement and product quality estimates generated during Phase I
- Establishment of processing parameter information for the Phase IV Economic Evaluation Study

Two feedstocks were used in this phase of the project. The first was shale oil derived from Occidental Petroleum Company's Modified In-Situ retorting process, and the second was shale oil obtained from the above-ground Paraho direct-heated retort. This work was summarized in Report Number AFWAL-TR-81-2116 entitled "United States Air Force Shale Oil to Fuels -- Phase II Interim Report" issued in November, 1981.

The objectives of the Phase III program included:

- Demonstration of first-stage hydrotreater catalyst stability
- Production of 5-gallon samples of jet and diesel fuels using the parallel-flow hydrocracking scheme
- Demonstration of hydrocracker catalyst stability
- Production of a 5-gallon sample of Special Grade gasoline using the Platforming process
- Investigation of crude shale oil arsenic solubilization and passivation or extraction of arsenic from used hydrotreating catalysts
- Determination of the relative fouling characteristics of raw and hydroprocessed shale oil fractions
- Examination of the stability and compatibility of shale oil and petroleum blends

The objectives of the Phase IV program included:

- Production of cost estimate based on process designs for the first-stage hydrotreater, second-stage hydrotreater and hydrocracker.
- Development of a shale oil refinery model
- Analysis of the economics of jet fuel production from raw shale oil

The results of the Phase III and Phase IV programs are contained in this final report.

The various operating conditions used during the pilot plant studies are consistent with commercial operating experience based on petroleum derived oils. All of the data presented in this report have operating conditions reported relative to a base operating condition. In all cases, the base conditions selected are those required to process a typical Middle East petroleum of the same boiling range to the identical product requirements. Positive differences in operating conditions indicate more severe requirements; negative differences indicate less severe processing requirements.

## SECTION II

### FIRST-STAGE HYDROTREATING

A six-month, first-stage hydrotreating run was made to provide additional processing and catalyst stability data required to establish the equipment design for a commercial plant. The specific data needed for this design work were the effect of metals deposition, particularly arsenic and iron, on catalyst activity and stability, when accomplishing the objective of reducing the arsenic content to less than 1 ppm.

#### Pilot Plant Description

A schematic diagram of the pilot plant used for this run is shown in Figure 1. Fresh feed and hydrogen are combined and flow concurrently downflow over the catalyst. The reactor effluent passes to a series of separators where the gas (mainly hydrogen) is separated, water scrubbed and recycled back to the reactor together with makeup hydrogen. The liquid is sent to a stripper to remove hydrogen sulfide and ammonia and is then collected under nitrogen in a glass receiver.

Based on the previously completed experimental work, the catalyst designated DRA was selected for this run. This proprietary, commercially-proven catalyst was developed to hydrotreat feeds containing large amounts of metal contaminants.

#### Feedstock

The feedstock was an Occidental shale oil produced from a modified in-situ retort. The "as-received" shale oil was dewatered and desalted in a two-stage electric desalter. Inspections of the treated shale oil are shown in Table 1. This 22.9 °API gravity material contained 1.51 wt-% nitrogen, 27.5 ppm arsenic, and 45 ppm iron.

This feedstock was subjected to inspection throughout the six-month operation. As indicated on Table 2, the API gravity, distillation, and Bromine number show the expected variations in the test results. The values for arsenic show a broad range with many points below the 27.5 ppm level given in Table 1. The 60 ppm iron values in Table 2 are fairly consistent and higher than the 45 ppm level of Table 1.

### Operating Conditions

Process conditions used in this study are comparable to those commercially employed for hydrotreating coke-oven light oil. The nomenclature adopted to relate the actual operating conditions to these base conditions is as follows:

		<u>Written as</u>
Temperature (Catalyst Average)	T-T (base), °F	T-T <sub>B</sub>
Pressure	P-P (base), psi	P-P <sub>B</sub>
Space Velocity	LHSV/LHSV base	L/L <sub>B</sub>
H <sub>2</sub> Recycle	SCFB/SCFB (base)	H/H <sub>B</sub>

The start-of-run operating conditions were as follows:

Temperature	T-T <sub>B</sub> , °F	50
Pressure	P-P <sub>B</sub> , psi	0
Space Velocity	L/L <sub>B</sub>	0.33
H <sub>2</sub> Recycle	H/H <sub>B</sub>	1.33

### Stability Study Discussion

At the operating conditions given above, the catalyst maintained its activity for arsenic removal for the entire 170-day run. As shown in Figure 2, the product arsenic content was maintained at less than 0.2 ppm with no increase in catalyst temperature.

While achieving the desired arsenic removal level, the feed iron content was reduced to about 0.5 ppm for the entire run with no obvious

tendency to increase. The sulfur removal activity was also relatively constant giving a product value of about 0.05 wt-% for 92% removal.

A detailed, composite product analysis from late in the run is shown in Table 1. Product analyses completed at points throughout the run are given in Table 3. These data show that oxygen removal was relatively constant at about 50% whereas the nitrogen removal activity decreased from about 47% at start-of-run to about 22% at end of run. The conversion of the Conradson carbon components was relatively constant at 67%.

The overall yields for this operation are given in Table 4 and indicate a C<sub>6</sub> plus product in the range of 99 wt-% of fresh feed. About 580 standard cubic feet per barrel (SCFB) of hydrogen were required to accomplish this task.

At the end of the run, the catalyst was unloaded in five sections. It was free flowing and showed no signs of fouling. The used catalyst analysis given in Table 5 shows the pattern of higher to lower concentration of metal deposition from catalyst inlet to outlet. About 8.5 wt-% of arsenic was found on the chloroform-extracted catalyst removed from the top of the bed. The arsenic profile indicates that even after this six-month operation, the RCD catalyst had not reached its metals-limited capacity.

Fouling did occur three times during the course of the run. Each time, a deposit was formed at the top of the quartz chip preheater zone which caused a high pressure drop across the reactor, resulting in a "forced" shutdown. The reactor was opened and the fouled material removed and replaced. No loss in catalyst activity was observed as a result of these shutdowns.

The composition of the fouled material removed from the preheater in these three instances was quite similar. The data in Table 6 show that major constituents found on the quartz chips were carbon, hydrogen, arsenic, iron and sulfur, the remaining being trace metals. The presence

of these components is indicative of more than one fouling mechanism. These data also indicate that a successful commercial unit must have special features to accommodate these foulants.

The solids present in the desalted Occidental shale oil were subjected to additional analysis. A scanning electron microscope (SEM) was used to characterize the residue trapped on 5 micron filters and the toluene insoluble solids. As shown in the photographs of Figure 3 and 4, the material ranged in size from 5 to 200 microns, with the majority of the particles in the 10-20 micron range. Residue morphologies varied. The two most prevalent forms being agglomerated particles (often comprised of dense, flat platelets) and smooth dense individual particles exhibiting rounded edges.

The elemental analysis of the ash derived from these solids is given in Table 7. Using the emission spectrographic technique, analyses were completed on both the dry ash and the wet ash (sample is digested in sulfuric acid before ashing). Based on the large difference in the iron content, which is reported as ppm of metal in the oil, some of the iron-containing compounds may have been volatilized in the dry ash procedure. There are some inconsistencies in these data which remain unexplained and deserve further analysis. It can be concluded, however, that there is a wide size range of solids and that iron, nickel, sodium, calcium, magnesium and zinc are important components.

### Conclusions

Based on the results of the six-month, first-stage hydrotreating operation, it is concluded that:

1. The UOP catalyst maintained its activity and stability for arsenic and iron removal over the entire 170-day run.
2. A total of 30 wt-% metals was accumulated on the catalyst during the course of the run.

3. Product arsenic was consistently below 1 ppm and iron at 1 ppm or less.
4. The fouling which occurred in the pilot plant preheater zone must be considered in the design of a commercial unit.
5. Additional experimental work to characterize the solids and investigate the fouling mechanisms is recommended.

TABLE 1. FIRST-STAGE HYDROTREATING  
OCCIDENTAL SHALE OIL

Feed and Product Comparison

	<u>Feed</u>	<u>Product</u>
API Gravity at 60°F	22.9	26.7
Specific Gravity at 60°F	0.9165	0.8944
Distillation (D-1160), °F		
IBP	376	370
5%	467	472
10%	570	508
30%	670	600
50%	712	698
70%	820	799
90%	953	940
95%	-	984
EP	-	-
% Over	87	92
Pour Point, °F	+65	+75
<u>Viscosities</u>		
Kinematic at 122°F, cSt	21.94	11.54
Kinematic at 210°F, cSt	5.268	3.473
Carbon, wt-%	84.85	84.85
Hydrogen, wt-%	12.27	12.63
Total Nitrogen, wt-%	1.51	1.17
Sulfur, wt-% (ppm)	0.64	(479)
Chloride, wt-ppm	<1.0	-
BS and W, vol-%	0.2	-
Conradson Carbon, wt-%	1.36	0.45
Ash, wt-%	0.014	0.001
Heptane Insolubles, wt-%	0.34	0.01
Pentane Insolubles, wt-%	1.65	0.07
Metals by Emission (AAS), ppm		
Fe	45	(0.2)
Ni	6.7	(2.2)
V	0.42	(< 0.1)
Pb	< 0.1	
Cu	< 0.1	
Na	11	
Mo	1.6	
Arsenic, wt-ppm	27.5	< 0.1
Bromine No.	23.6	7.5
Oxygen, wt-%	0.65	0.34
Water, wt-%	0.05	

TABLE 2. PERIODIC FEEDSTOCK ANALYSIS DURING STABILITY DEMONSTRATION

Period	1	95	138	198	246	270	318
Hours on Stream	Startup	1128	1654	2376	2952	3240	3816
API at 60°F	22.7	23.3	23.2	22.5	22.6	23.0	23.2
Sp. Gr. 60/60°F	0.9176	0.9141	0.9147	0.9188	0.9182	0.9159	0.9147
Distillation (D-1160), °F							
IBP	393	378	374	370	365	400	394
5%	478	459	468	458	480	482	488
10%	509	503	502	500	508	510	522
20%	570	569	560	560	559	561	572
30%	620	629	619	610	608	619	622
40%	675	688	675	659	660	680	672
50%	722	739	731	712	714	735	722
60%	770	789	781	771	769	787	780
70%	823	835	830	830	821	834	830
80%	882	880	881	883	871	882	890
85%				910		909	959
87%					930		
88%	941						
90%		979					
% Over	88.0	90.0	85.0	85.0	87.0	85.0	90.0
% Bottoms	12.0	10.0	15.0	15.0	13.0	15.0	10.0
Bromine Number	25.6	27.0	20.0	19.8		19.8	21.1
Arsenic, ppm	14.8	15.9	12.0	16.5	13.3	24	29
Iron, ppm	59.2	60	54	58	60	62	60
Ash, ppm		0.017		0.011			

TABLE 4. SINGLE-STAGE HYDROTREATER  
OCCIDENTAL SHALE OIL

Product Yields

Yields, Wt-% of Feed

H <sub>2</sub> O	0.50
NH <sub>3</sub>	0.50
H <sub>2</sub> S	0.65
C <sub>1</sub>	0.03
C <sub>2</sub>	0.06
C <sub>3</sub>	0.09
C <sub>4</sub>	0.12
C <sub>5</sub>	0.15
C <sub>6</sub> +	<u>98.86</u>
Total	100.96

Chemical Hydrogen Consumption = 581 SCFB

TABLE 5. FIRST-STAGE STABILITY DEMONSTRATION RUN

Used Catalyst Analyses

	<u>Top</u>	<u>Top Middle</u>	<u>Middle</u>	<u>Bottom Middle</u>	<u>Bottom</u>
Arsenic, wt-%	8.42	5.58	3.35	1.58	1.31
Iron, wt-%	6.00	3.74	1.91	0.99	0.90
Carbon, wt-%	9.11	10.20	10.07	10.16	10.32
Sulfur, wt-%	6.20	6.38	5.66	5.77	5.51
Nitrogen, wt-%	0.39	0.43	0.43	0.85	0.22

TABLE 6. FIRST-STAGE STABILITY DEMONSTRATION RUN

Preheater and Plug Material

Time on Stream, Days	55		92		128	
Location	Top	Bottom	Top	Top	Top	Top
Dry Ash, wt-%	85.4	98.3	85.7		87.1	
Carbon, wt-%	10.4	0.90	10.78	0.43	10.70	1.70
Hydrogen, wt-%	-	-	1.56		1.48	
Arsenic, AAS, wt-%	-	-	-	0.11	0.56	0.43
Sulfur, wt-%	-	-	-	-	1.52	-

## Method:

Emission Spec.	Quartz*						
	Chips	Dry Ash		Wet Ash	Dry Ash	Wet Ash	
Metal, wt-%							
Fe	0.044	3.4	1.2	1.2	0.96	2.4	2.6
Ni	0.004	0.064	0.052	<0.03	<0.03	0.12	0.13
V	-	<0.003	<0.003	-	<0.03	-	<0.03
Ca	<0.03	0.068	0.032	-	<0.2	<0.3	<0.2
Mg	0.006	0.010	0.005	0.015	0.012	<0.01	0.015
Mn	0.002	0.012	0.009	0.015	0.020	0.015	0.014
Cr	0.002	0.039	0.007	0.038	0.098	0.025	0.03
Sn	-	0.010	<0.003	<0.03	<0.03	<0.03	<0.03
Cu	<0.001	0.059	0.013	0.013	<0.01	0.017	0.017
Zn	-	0.015	0.25	<0.3	<0.4	<0.4	<0.4
Ti	0.16	0.18	0.18	0.32	0.58	0.30	0.35
Pb	-	0.003	<0.001	<0.03	<0.04	<0.04	<0.04
Na	<0.05	0.45	0.025	<1.0	<1	<0.5	<1
Mo	-	0.13	0.059	0.043	<0.04	0.11	0.16
Co	0.021	0.006	0.070	0.078	0.086	0.15	0.15
Si	Major						
Al	0.46	0.49	0.58	0.37	0.60	0.38	0.45
Zr	0.006	-	-				
B	0.03	-	-				
Ba	0.006	0.007	0.005				

\* This analysis is included to provide a point of reference.

TABLE 7. SOLIDS ANALYSIS

## Desalted Occidental Shale Oil

Fraction Analyzed	Total	Filter Cake on		
	Sample	5 $\mu$ m Filter	10 $\mu$ m Filter	25 $\mu$ m Filter
Properties of Sample				
Ash Content (Dry), ppm	165			
Ash ASTM D-482, wt-%	0.015			
Toluene Insoluble, UOP 614, wt-%	0.01			
Stability, ASTM D-1661				
Thimble Rating				
Unwashed	stable			
Unwiped, Washed	stable			
Wiped, Washed	stable			
Stability, UOP 174	stable			
BS&W before O <sub>2</sub>	<0.05			
BS&W after O <sub>2</sub>	<0.05			
Toluene Insoluble on 5 $\mu$ m Filter, wt-%	0.005			
Toluene Insoluble on 10 $\mu$ m Filter, wt-%	0.005			
Toluene Insoluble on 25 $\mu$ m Filter, wt-%	0.003			

## Emission Spectrographic Analysis of Ash

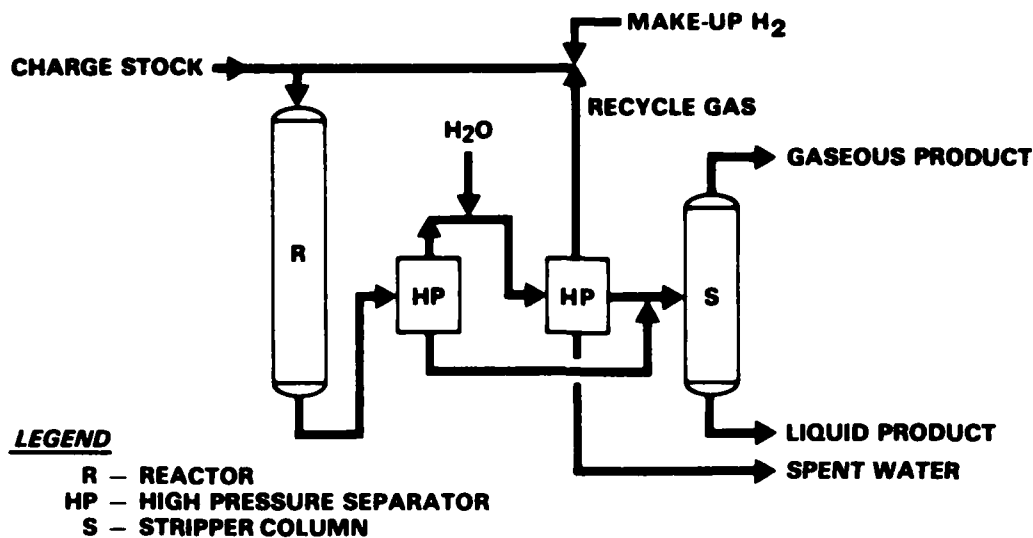
Elements	Reported as ppm metal in the oil	**	**	**
Fe	7.4	9.8	23.0	8.3
Ni	18	0.02	0.07	0.04
V	0.84	0.02	0.02	0.02
Mn	0.18	0.02	0.03	0.01
Cr	0.31	0.02	0.03	0.01
Pb	0.14	0.09	0.15	0.07
Sn	0.32	0.21	0.22	0.14
Cu	4.3	0.05	0.07	0.03
Zn	6.3	0.53	0.61	0.31
Ti	0.50			
Al	Diluent	0.27	0.40	0.13
Mg	2.1	0.50	0.23	0.09
Ca	5.5	1.1	2.6	0.33
Na	8.4	3.1	6.9	1.9
Mo	3.3	0.02	0.03	0.01
Si	2.6			
Co	4.8			
B*	0.5			

## Emission Spectrographic Analysis of Wet Ash

Elements	Reported as ppm metal in the oil
Fe	58
Ni	12
V	0.68
Pb	<0.05
Cu	0.19
Na	9.9
Mo	4.0

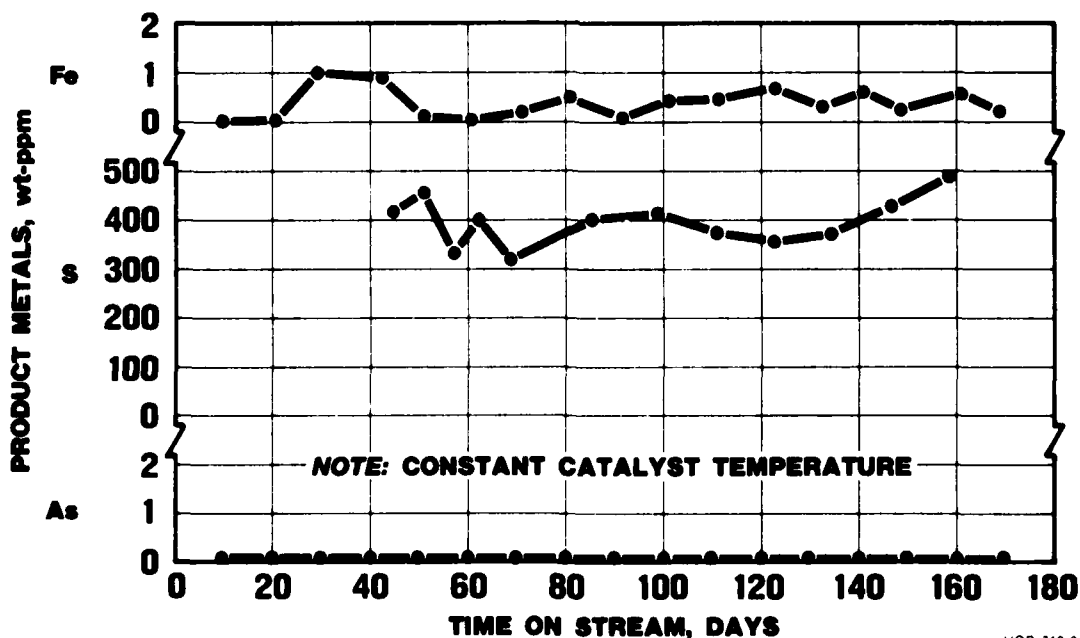
\* Est. only.

\*\* Semi-Quantitative/Samples reacted with quartz beakers.



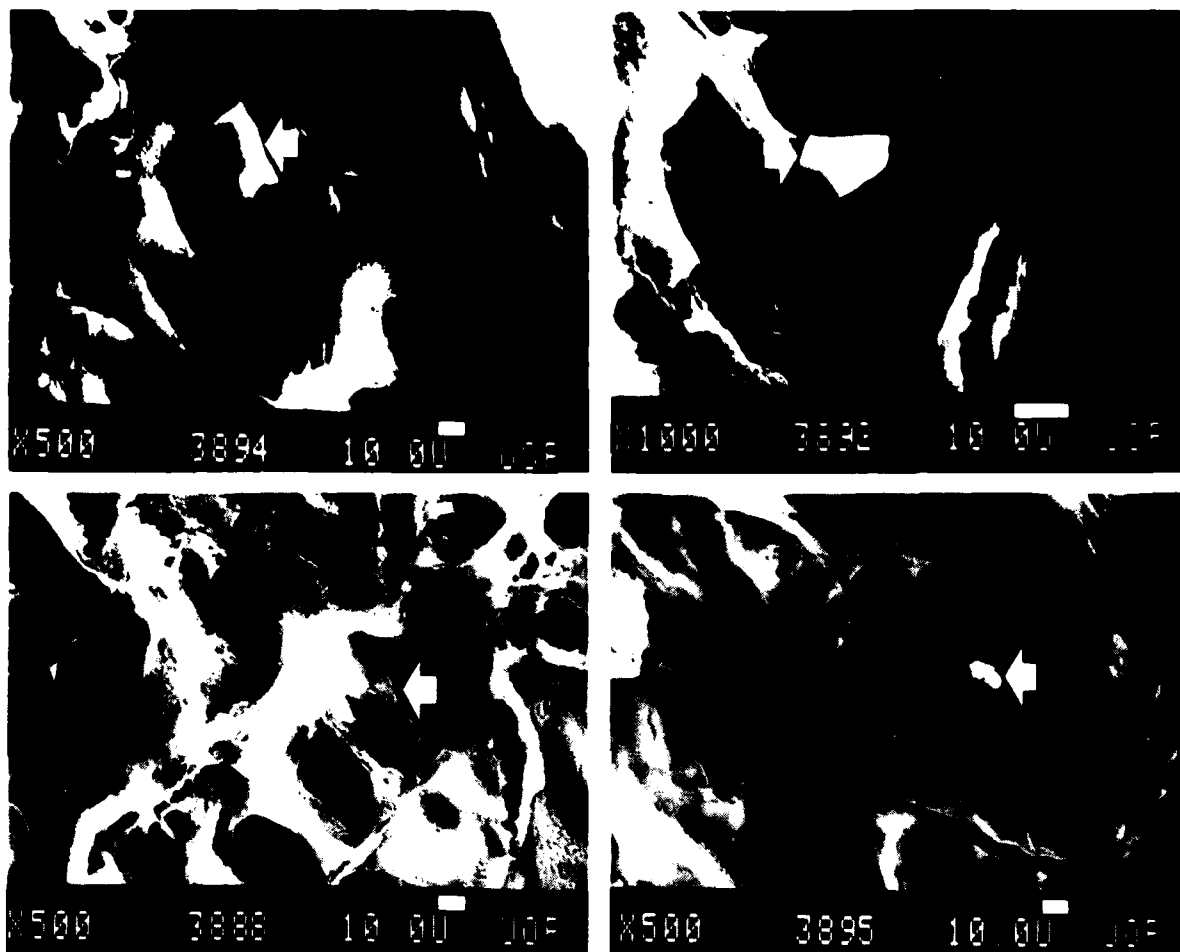
UOP 525.77  
 UOP 710-1

**FIGURE 1**  
**FIRST STAGE HYDROTREATING**  
**PILOT PLANT**  
**SCHEMATIC FLOW DIAGRAM**



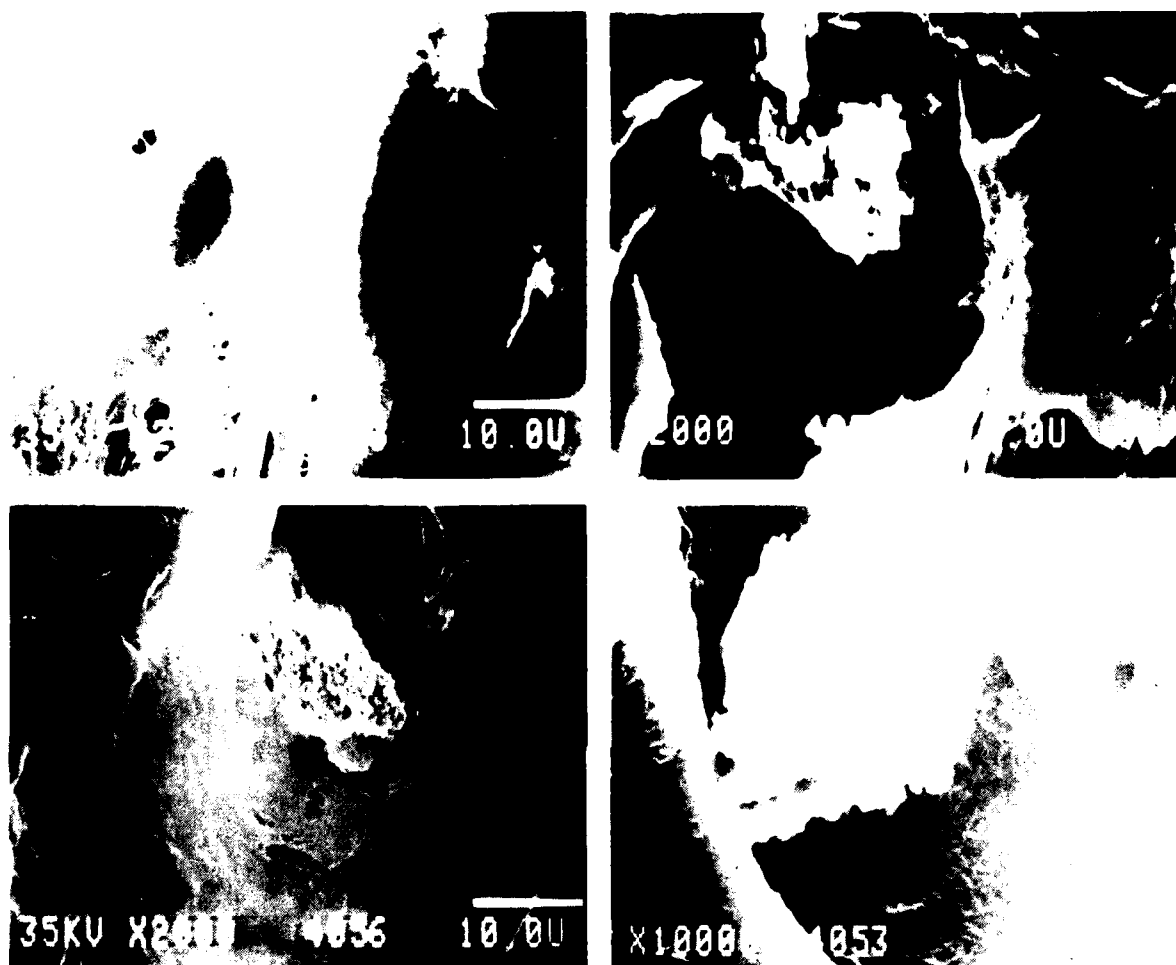
UOP 710-2

**FIGURE 2**  
**FIRST STAGE HYDROTREATING**  
**CATALYST STABILITY**  
**DEMONSTRATION**



UOP 734-23

**FIGURE 3**  
**SCANNING ELECTRON**  
**MICROSCOPE ANALYSIS OF**  
**OCCIDENTAL SHALE OIL**  
**RESIDUE**



UOP 734-24

**FIGURE 4**  
**SCANNING ELECTRON**  
**MICROSCOPE ANALYSIS OF**  
**OCCIDENTAL SHALE OIL**  
**TOLUENE INSOLUBLES**

## SECTION III

### HYDROCRACKING

As part of the Phase III pilot plant program, three hydrocracking studies were completed: preparation of 5-gallon samples of jet and diesel fuels, determination of catalyst stability in the parallel-flow scheme, and investigation of sulfur addition to the hydrocracker feedstock. The data developed from these studies were also used to confirm the refinery design and provide other information needed in the economic evaluation program of Phase IV.

#### Pilot Plant Description

The pilot plant used in the hydrocracking operation embodies the essential features of a commercial unit. Fresh feed, recycle liquid, recycle gas and makeup hydrogen are charged to the reactor section. Trickle-bed reactors containing 25-200 mL of catalyst were employed. Gas is recycled from the high pressure separator back to the reactor section. The reactor liquid effluent is charged to a series of separators including a fractionator and debutanizer to produce liquid product and a recycle liquid stream. In the pilot plant operations, reactor temperatures were adjusted to achieve 100% conversion of the feed to products. During these operations, no fractionator bottoms product was withdrawn as a net product.

The DCC catalyst used in this study is a proprietary material which has seen wide commercial operation. This is the same catalyst which was used successfully in the Phase II hydrocracking programs.

#### Feedstock

The hydrocracker feedstock is a second-stage hydrotreated Occidental shale oil, whose properties are shown in Table 8. This stock was produced

by first hydrotreating the raw shale oil at relatively mild conditions to remove the contaminants and stabilize the material, and then hydrotreating the first-stage product at relatively severe conditions to reduce the high levels of impurities, such as nitrogen and oxygen, that were still present. The measured nitrogen content of the material was 780 ppm. The hydrocracker feed sulfur content was 139 ppm, the oxygen content 545 ppm, and the Bromine number 1.1.

#### Operating Conditions

The operating conditions used in the production of the fuel samples were in the range of those commercially practiced, and for this report, are presented relative to the conditions appropriate for converting a typical Arabian vacuum gas oil. The nomenclature adopted is as follows:

		<u>Written as</u>
Temperature (Catalyst Average)	T-T (base), °F	T-T <sub>B</sub>
Pressure	P-P (base), psi	P-P <sub>B</sub>
Space Velocity	LHSV/LHSV (base)	L/L <sub>B</sub>
Combined Feed Ratio	CFR/CFR (base)	C/C <sub>B</sub>
H <sub>2</sub> Recycle	SCFB/SCFB base	H/H <sub>B</sub>

The conditions in the two operations, Runs 1 and 2, were varied depending on the type of fuel being produced. Run 1 was designed to produce the jet fuel samples. The latter portion of the run was used to establish operating conditions and procedures for the diesel fuel production and the stability demonstration, in Run 2.

Run 2 proceeded initially in the JP-8 mode to obtain the base activity-conversion level. This was followed by the more severe diesel fuel production mode. The final processing was again in the JP-8 mode to obtain the final activity-conversion level and the catalyst deactivation rate.

Run	1			2			
Type of Fuel	JP-8	JP-4	Diesel	JP-8	Diesel	JP-8	JP-8
Hours on Stream	70-360	360-610	610-860	0-150	150-460	460-780	780-1293
Temperatures, (T-T <sub>B</sub> ), °F	-54	-50	-44	-53	-49	-43	-45
Pressure, (P-P <sub>B</sub> ), psig	-150						
Space Velocity, (L/L <sub>B</sub> )	1.4	1.4	2.0	1.4	2.0	1.4	1.4
CFR, (C/C <sub>B</sub> )	1.0	1.0	0.8	1.0	0.8	1.0	1.0
H <sub>2</sub> Recycle, (H/H <sub>B</sub> )	1.4						

#### Sample Production

Representative product yield distributions obtained when hydrocracking the hydrotreated Occidental shale oil to JP-4 and JP-8 fuels are given in Table 9. The JP-4 yield was better than 84 wt-% and required 1029 SCFB of hydrogen. The JP-4 volume yield amounted to about 93 vol-% of hydrocracker feed. The equivalent values for JP-8 are 75 wt-% yield (80 vol-%) with 921 SCFB hydrogen consumption. Both of these yield patterns show the excellent selectivity of the parallel-flow scheme for jet fuel production.

More detailed product distributions for the JP-4 and JP-8 cases are given in Tables 10 and 11, respectively. Both of these analyses are from single test periods and differ slightly from the average values given in Table 9. Included with the more detailed light ends yields are the iso- and normal-paraffin breakdown for the butanes and pentanes. About 60 wt-% of the butanes and 67 wt-% of the pentanes are in the more valuable non-normal configuration.

The UGP inspections of the JP-4 jet fuel sample are shown in Table 12 along with the USAF specifications. With the exception of the slightly high 50 and 90% points of the distillation and the conductivity, this

product meets all U.S. military specifications and should be environmentally acceptable in view of the low nitrogen and sulfur contents. With only 8.7 vol-% aromatics reported (25.0 vol-% is the maximum specification), the Smoke Point exceeds the minimum acceptable level of 20 by 8.5. The net combustion value is some 300 Btu/lb higher than required and is a reflection of the high hydrogen content obtained in the parallel-flow hydrocracking operation.

Inspections of the JP-8 jet fuel produced are shown in Table 13, along with the USAF specifications. These inspections meet all of the U.S. military specifications except for Freeze Point ( $-54^{\circ}\text{F}$  vs.  $-58^{\circ}\text{F}$ ) and conductivity. These can be easily met by slightly lowering the end point and including an additive, respectively. This higher end point fuel,  $552^{\circ}\text{F}$  vs.  $517^{\circ}\text{F}$  for the JP-4, contains 9.7 vol-% aromatics and gave a Smoke Point of 27.2 (minimum specification is 25). The combustion value is 200 Btu/lb higher than required and again shows the high hydrogeneration capability of the parallel-flow hydrocracking operation.

An analysis of the  $\text{C}_5\text{-C}_6$  fraction obtained during the JP-8 production run is given in Table 14. This material is highly isomerized and contains less than 1 wt-% benzene. The clear Research octane number of 70.6 increased to 87.7 with the addition of 3 cc TEL per gallon.

A detailed analysis of the  $\text{C}_7\text{-232}^{\circ}\text{F}$  naphtha yielded during the JP-8 production run is given in Table 15. This highly saturated material contains 96.8 vol-% paraffins plus naphthenes and has a clear Research octane number of 60.2. After treatment to remove the small quantity of sulfur remaining, this naphtha represents a good feedstock for further upgrading by catalytic reforming to produce both a high octane blending component and hydrogen for the shale oil hydrotreating operations. The catalytic reforming of this material is discussed later in this report.

The product distributions for hydrocracking the hydrotreated Occidental shale oil to DF-2 and DFM are shown in Table 16. The yields of 98.6 wt-% and 96.2 wt-% were achieved for DF-2 and DFM, respectively. Both fuels were produced with the same end point and, therefore, the yield

difference results from adjusting the amount of C<sub>5</sub>-C<sub>6</sub> material in the product to meet the specified flash points. As noted in the jet fuel production cases, the parallel-flow hydrocracking scheme showed excellent selectivity for converting the hydrotreated shale oil into these distillate fuels. The chemical hydrogen consumption was 800 SCFB for both the DF-2 and DFM cases.

A more detailed product distribution obtained in a single test period in the diesel fuel production mode is given in Table 17. The C<sub>4</sub>- yield in this operating mode is only about one-third that observed in the more severe jet fuel operations. The extent of butane and pentane isomerization is about the same: 60% iso in the total butane and 67% iso in the total pentane.

Inspections of the DF-2 and DFM samples, together with the U.S. military specifications, are shown in Tables 18 and 19, respectively. These inspections show that the diesel fuels met all specifications. Both samples had Cetane numbers greater than 55 and very low sulfur contents of about 1 ppm. Both diesel fuels show excellent stability and should be environmentally acceptable. In addition, their low acid numbers, copper strip corrossions, sediments, particulates, excellent stabilities and high cetane numbers should pose no problem for storage and use in engines.

#### Catalyst Stability Demonstration

A second objective in the Phase III hydrocracking program was to make an extended catalyst stability study to provide information regarding longer term effects of processing shale oil in the proposed UOP turbine fuels refinery and to assess the advantage of parallel-flow over single-stage hydrocracking in terms of catalyst stability.

As indicated previously, the stability run was made in the same hydrocracking operation used for the sample production. After checking the plant operation in the JP-8 mode for 150 hours, and then producing the diesel samples, the plant was switched back to the JP-8 mode, and the operation continued for a period of 1200 hours to measure the catalyst deactivation.

The deactivation was measured by the increase in reactor temperature per unit of operating time required to maintain constant conversion to a specified product end point. In this case, the end point was that required to make JP-8 jet fuel. Results of the run are shown in Figure 5. The rate of deactivation is slightly lower than was reported for a similar operation over a shorter period of time in the Phase II program and as shown in the Phase II report, much improved over the expected result for the single-stage operation.

During the catalyst stability demonstration (Run 2), and at the end of Run 1, plugging of the reactor preheater was observed. Elemental analyses of the material recovered from the inert, granular material (quartz chips) are given in Table 20. Relatively high concentrations of iron, nickel and chromium are found. Analyses of the carbonaceous material found at the same time periods on a filter in the fresh feed line, as given in Table 21, indicate the presence of high molecular weight, hetero-atomic materials. The presence of these materials in the hydrotreated feedstock and their subsequent fouling of the reactor preheater are believed due to oxidation and degradation as a result of handling and storing this material during a 9-month period.

#### Sulfur Addition

In the Phase II hydrocracking program, it had been observed that the addition of sulfur to the relatively sulfur-free hydrocracker feedstock improved the activity of the catalyst. With the feedstock containing less than 3 ppm sulfur, it was suspected that this was insufficient to maintain the catalyst in its activated (sulfided) state.

After the period in which the stability of the catalyst was demonstrated, 10,000 ppm of sulfur as ditertiary-butyl disulfide was added to the feed. As before, the catalyst temperature required to maintain conversion was reduced by about 10°F. The presence of plant operating problems in the fractionation section forced this study to be discontinued before a definitive response could be determined.

## Conclusions

Based on the results of these hydrocracking operations, it was concluded that:

1. The parallel-flow hydrocracker can produce military turbine fuels and diesel fuel in excellent yields.
2. These fuels not only meet, but exceed, military specifications in many areas.
3. The parallel-flow hydrocracker offers improved catalyst stability when compared with conventional single-stage hydrocracking.

TABLE 8. HYDROCRACKING FEEDSTOCK

## Occidental Shale Oil

		<u>Boiling Pt. GC, Wt-%</u>	
		% Over	Temp., °F
API Gravity at 60°F	32.0	IBP	241
Sp. Gr., 60/60°F	0.8654	5	361
Distillation (D-1160), vol-%		10	421
IBP, °F	390	15	463
5%	469	20	495
10%	495	25	519
30%	581	30	545
50%	663	35	571
70%	760	40	592
90%	898	45	615
95%	958	50	640
EP, °F	988	55	666
% Over	97.0	60	692
Carbon, wt-%	86.99	65	718
Hydrogen, wt-%	13.41	70	747
Nitrogen, ppm	780	75	776
Sulfur, ppm	139	80	804
Pentane Insolubles, wt-%	0.12	85	832
Heptane Insolubles, wt-%	0.05	90	872
Conradson Carbon, wt-%	0.09	95	931
Ash, wt-%	0.001	FBP	1100
Bromine Number	1.1		
BS & W, wt-%	0.4		
Toluene Insolubles, wt-%	0.01		
Oxygen, ppm	545		
Molecular Weight	305		

TABLE 9. HYDROCRACKER PRODUCT DISTRIBUTIONS

Hydrotreated Occidental Shale Oil Feed

Product Desired	JP-8	JP-4
<u>Wt-%</u>		
Fresh Feed	100.00	100.00
H <sub>2</sub> Consumption, wt-%	1.61	1.80
H <sub>2</sub> Consumption, SCFB	921	1029
NH <sub>3</sub>	0.08	0.08
H <sub>2</sub> S	0.01	0.01
C <sub>1</sub> -C <sub>3</sub>	1.50	1.88
C <sub>4</sub>	3.73	4.80
C <sub>5</sub> -C <sub>6</sub>	9.29	11.03
C <sub>7</sub> -250°F	11.75	JP-4 { 12.18
250-EP	JP-8 <u>75.25*</u>	
Total	101.61	<u>71.82**</u>
<u>Vol-%</u>		
Fresh Feed	100.00	100.00
C <sub>4</sub>	5.78	7.43
C <sub>5</sub> -C <sub>6</sub>	12.62	14.75
C <sub>7</sub> -250 °F	13.76	JP-4 { 14.31
250-EP	JP-8 <u>80.40*</u>	
Total	112.56	<u>78.68**</u>

\* Product EP ~550°F

\*\* Product EP ~520°F

TABLE 10. HYDROCRACKING HYDROTREATED OCCIDENTAL SHALE OIL

JP-4 Product Distribution

	<u>Yield, Wt-%</u>	<u>Yield, Vol-%</u>	<u>Gas Yield, SCF/BBL</u>
Hydrogen	0.23		
H <sub>2</sub> S	0.01		
NH <sub>3</sub>	0.16		
Methane	0.24		16.4
Ethane	0.25		9.1
Propane	1.39		34.2
Isobutane	2.83	4.44	53.0
n-Butane	1.97	2.98	36.9
Isopentane	3.29	4.63	
n-Pentane	1.70	2.37	
Hexane	6.03	7.74	
C <sub>7</sub> -250°F Fraction	12.17	14.29	
250-EP Fraction	71.74	78.59	
Total	102.01	115.03	149.7
Subtotals			
C <sub>1</sub> -C <sub>4</sub> Fraction	6.68		149.7
C <sub>5</sub> -C <sub>6</sub> Fraction	11.02	14.73	
C <sub>7</sub> -250°F Fraction	12.17	14.29	
250-EP Fraction	71.74	78.59	
C <sub>5</sub> + Fraction	94.93	107.61	
Percent <u>Iso</u> in			
Butane	58.94		
Pentane	65.85		

TABLE 11. HYDROCRACKING HYDROTREATED OCCIDENTAL SHALE OIL

JP-8 Product Distribution

	<u>Yield, Wt-%</u>	<u>Yield, Vol-%</u>	<u>Gas Yield, SCF/BBL</u>
Hydrogen	0.22		
H <sub>2</sub> S	0.01		
NH <sub>3</sub>	0.16		
Methane	0.18		12.0
Ethane	0.18		6.5
Propane	1.09		26.9
Isobutane	2.42	3.81	45.4
<u>n</u> -Butane	1.52	2.29	28.4
Isopentane	3.02	4.26	
<u>n</u> -Pentane	1.42	1.97	
Hexane	4.98	6.60	
C <sub>7</sub> -232°F Fraction	7.73	8.71	
232-EP Fraction	78.90	85.65	
Total	101.83	113.28	119.2
Subtotals			
C <sub>1</sub> -C <sub>4</sub> Fraction	5.39		119.2
C <sub>5</sub> -C <sub>6</sub> Fraction	9.42	12.83	
C <sub>7</sub> -232°F Fraction	7.73	8.71	
232-EP Fraction	78.90	85.65	
C <sub>5</sub> + Fraction	96.05	107.18	
Percent <u>Iso</u> in			
Butane	61.5		
Pentane	68.1		

TABLE 12. JP-4 JET FUEL

<u>Production Sample</u>		
	<u>USAF Specs.</u>	
API Gravity at 60°F	45-57	49.6
Sp. Gr. 60/60°F		0.7813
Distillation (D-86), vol-%		
IBP, °F	report	202
5%		236
10%	report	255
20%	293	288
30%		321
40%		354
50%	374	386
60%		414
70%		437
80%		456
90%	473 max.	478
95%		495
EP, °F	518 max.	517
Freeze Point, °F	-72 max.	Below -70°F
Smoke Point	20 min.	28.5
Vapor Pressure, 38°C, psi	2-3 max.	0.8
Viscosity -20°C, cSt		3.207
Acid No., mg KOH/mg	0.015 max.	0.012
Copper Strip Corrosion	1B max.	1A
Coulometric Sulfur, ppm	0.4 wt-% max.	737
Mercaptan Sulfur, wt-%	0.001 max.	0.0001
Coulometric N, ppm		0.37
Carbon, wt-%		84.23
Hydrogen, wt-%	13.6 min.	14.39
FIA, vol-%		
P + N		91.3
O	5.0 max.	-
A	25.0 max.	8.7
Combustion, Btu/lb	18,400 min.	18,700
Existent Gum,		
Unwashed/Washed, mg per 100 mL	7 max.	7.8/4.0
Naphthalenes, UV wt-%		0.28
Conductivity	50-300	1 p S/M
Water Separation D-1094		
Interface Rating	1B max.	1B
Separation Rating	1 max.	1
Demulsification		No Emulsion Oil Layer Clear No Scum

JFTOT

<u>Temp., °C</u>	<u>Min.</u>	<u>ΔP mm Hg</u>	<u>TDR Spun</u>	<u>ASTM Code</u>
260	150	1.5	1.5	0

TABLE 13. JP-8 JET FUEL

<u>Production Sample</u>		
	<u>USAF Specs.</u>	
API Gravity at 60°F	37-51	46.0
Sp. Gr. 60/60 F	0.775-0.840	0.7972
Distillation (D-86), vol-%		
IBP, °F	report	288
5%		308
10%	401 max.	321
20%		352
30%		384
40%		412
50%		434
60%		455
70%		474
80%		492
90%		512
95%		525
EP, °F	572 max.	552
% Over		99.0
Smoke Point	25 min.	27.2
Freeze Point, °F	-58 max.	-54
Flash Point, °F	100 min.	100
Viscosity -20°C, cSt	8.0 max.	5.670
Acid No., mg KOH/gm	0.015 max.	0.01
Coulometric Sulfur, ppm	0.4 wt-% max.	499
Mercaptan Sulfur, wt-%	0.001 max.	0.00048
Carbon, wt-%		84.63
Hydrogen, wt-%	13.6 min.	14.14
FIA, vol-%		
P + N		90.7
O	5.0 max.	-
A	25.0 max.	9.3
Combustion, Btu/lb	18,400 min.	18,600
Copper Strip Corrosion	1B max.	1A
Coulometric N, ppm		0.7
Existent Gum,		
Unwashed/Washed, mg per 100 mL	7 max.	4.1
Naphthalenes, UV wt-%	3 max.	0.35
Conductivity	50-300	4 p̄ S/M
Water Separation D-1094		
Interface Rating	1B max.	1
Separation Rating	2 max.	1

<u>JFTOT</u>					
	<u>Temp., °C</u>	<u>Min.</u>	<u>ΔP mm Hg</u>	<u>TDR Spun</u>	<u>ASTM Code</u>
	260	150	0	1.0	0

TABLE 14. C<sub>5</sub>-C<sub>6</sub> FRACTION FROM JP-8 JET FUEL

API 60°F	77.2	Composition by GC, Wt-%	
Sp. Gr., 60/60°F	0.6780		
Distillation (D-86), vol-%			
IBP, °F	124	<u>1</u> -C <sub>4</sub>	0.1
5%	134	<u>n</u> -C <sub>4</sub>	0.2
10%	136	<u>1</u> -C <sub>5</sub>	5.8
20%	140	<u>n</u> -C <sub>5</sub>	6.3
30%	141	2, 2 DMB	0.4
40%	144	CP	0.6
50%	146	2, 3 DMB	2.7
60%	148	2 MP	22.3
70%	150	3 MP	15.4
80%	152	<u>n</u> -C <sub>6</sub>	22.1
90%	156	MCP	17.2
95%	161	CH	2.1
EP, °F	220	Bz	0.9
% Over	99.0	C <sub>7</sub> +	3.9
Coulometric S, ppm	1.0		
Nitrogen, ppm (Chem Lum)	0.83		
RON Clear	70.6		
Leaded (3 cc TEL/gal)	87.7		

TABLE 15. C<sub>7</sub>-232°F FRACTION FROM JP-8 JET FUEL

API at 60°F	64.0		
Sp. Gr., 60/60°F	0.7238		
Distillation (D-86), vol-%		GC, Wt-%	
IBP, °F	194	Aromatics	
5%	197	Toluene	3.5
10%	198	m-Xylene	0.1
20%	199	Total	3.6
30%	201		
40%	202	Paraffins/Naphthenes	
50%	203	C <sub>6</sub> Paraffins	2.83
60%	205	C <sub>6</sub> Cyclics	2.74
70%	207	C <sub>7</sub> Paraffins	44.38
80%	209	C <sub>7</sub> Cyclics	28.34
90%	216	C <sub>8</sub> Paraffins	10.43
95%	222	C <sub>8</sub> Cyclics	8.39
* EP, °F	278	C <sub>9</sub> Paraffins	.19
% Over	99.0	C <sub>9</sub> Cyclics	0.10
			97.40
Coulometric S, ppm	17.1		
Nitrogen, ppm (Chem Lum)	0.40		
Carbon, wt-%	83.76		
Hydrogen, wt-%	16.00		
FIA, vol-%			
P + N	96.8		
O	-		
A	3.2		
RON Clear	60.2		
RON Leaded (3 cc TEL/gal)	82.2		

\* Dry Point = 232°F

TABLE 16. HYDROCRACKING HYDROTREATED OCCIDENTAL SHALE OIL  
TO DF-2 AND DFM DIESEL FUELS

Product Distribution, wt-%	<u>Feed</u>	<u>DF-2</u>	<u>DFM</u>
H <sub>2</sub> S		0.01	0.01
NH <sub>3</sub>		0.10	0.10
H <sub>2</sub> O		0.06	0.06
C <sub>4</sub> minus		1.68	1.68
C <sub>5</sub> and/or C <sub>6</sub>		1.00	2.36
Flash Point* to EP Diesel Fuel	44.0	<u>98.55</u>	<u>96.19</u>
Total		101.40	101.40
* Flash Point, °F		133	140
Hydrogen Consumption, SCF/B		800	

TABLE 17. HYDROCRACKING HYDROTREATED OCCIDENTAL SHALE OIL

Diesel Product Distribution

	Yield, Wt-%	Yield, Vol-%	Gas Yield, SCF/BBL
Hydrogen	0.13		
H <sub>2</sub> S	0.01		
NH <sub>3</sub>	0.10		
Methane	0.13		8.9
Ethane	0.11		4.0
Propane	0.38		9.3
Isobutane	0.68	1.07	12.7
n-Butane	0.48	0.72	8.9
Isopentane	0.82	1.16	
n-Pentane	0.40	0.56	
Hexane	1.30	1.72	
C <sub>7</sub> -183°F Fraction	0.19	0.16	
183-EP Fraction	96.77	100.78	
Total	101.51	106.17	43.8
Subtotals			
C <sub>1</sub> -C <sub>4</sub> Fraction	1.77		43.8
C <sub>5</sub> -C <sub>6</sub> Fraction	2.53	3.34	
C <sub>7</sub> -183°F Fraction	0.19	0.16	
183-EP Fraction	96.77	100.78	
C <sub>5</sub> + Fraction	99.49	104.28	
Percent <u>Iso</u> in			
Butane	58.8		
Pentane	67.05		

TABLE 18. DIESEL FUEL DF-2

Production Sample

	<u>USAF Specs.</u>	
API Gravity at 60°F	32.9-41	38.8
Sp. Gr. 60/60°F		0.8309
Distillation (D-86), vol-%		
IBP, °F		320
5%		362
10%		400
20%		452
30%		486
40%		513
50%	report	542
60%		568
70%		593
80%		618
90%	675 max.	646
95%		664
EP, °F	700 max.	678
% Over		98.5
Flash Point, °F	133 min.	134
Cloud Point, °F	report	32
Pour Point, °F		5
Aniline Point, °F		173.1
Viscosity 100°F, cSt	1.8-9.5	3.367
D-1500 Color	report	<2
Acid No., mg KOH/gm	0.10 max.	0.018
Copper Strip Corrosion, 100°C	1 max.	1A
Coulometric Sulfur, ppm	0.70 wt-% max.	1.2
Cetane Number	45 min.	55.1
Water and Sediment, D-2709, wt-%	0.01 max.	0.005
Demulsification, 25°C		No Emulsion Oil Layer Clear
Particulate Cont. D-2276, mg/L	8 max.	8
Carbon Residue on 10% Botts, D-524, wt-%	0.2 max.	0.11
Ash, wt-%	0.02 max.	0.001
Stability D-2274, mg/100 mL		
Adherent Gum	1.5 max.	0.45
Sediment		0.35
		Total 0.8

TABLE 19. DIESEL FUEL MARINE DFM

Production Sample

	<u>USAF Specs.</u>	
API Gravity at 60°F	report	38.7
Sp. Gr. 60/60°F		0.8314
Distillation (D-86), vol-%		
IBP, °F		348
5%		376
10%		420
20%		465
30%		498
40%		525
50%	report	550
60%		575
70%		598
80%		624
90%	675 max.	650
95%		672
EP, °F	725 max.	680
% Over		99.0
Flash Point, °F	140 min.	144
Cloud Point, °F	30 max.	28
Pour Point, °F	20 max.	5
Aniline Point, °F	report	173.1
Viscosity 100°F, cSt	1.7-4.3	3.444
D-1500 Color	3 max.	<3
Acid No., mg KOH/gm	0.30 max.	0.021
Copper Strip Corrosion, 100°C	1 max.	1A
Coulometric Sulfur, ppm	1.0 wt-% max.	1.9
Cetane Number	45 min.	55.3
Water and Sediment, D-2709, wt-%		<0.005
Demulsification, 25°C, minutes	10 max.	No Emulsion
		Oil Layer Clear
Particulate Cont. D-2276, mg/L		5
Carbon Residue on 10% Botts,		
D-524, wt-%	0.2 max.	0.11
Ash, wt-%	0.005 max.	<0.001
Stability D-2274, mg/100 mL		
Adherent Gum	2.0 max.	0.3
Sediment		0.3
		Total 0.7

TABLE 20. PREHEATER PLUG ANALYSES

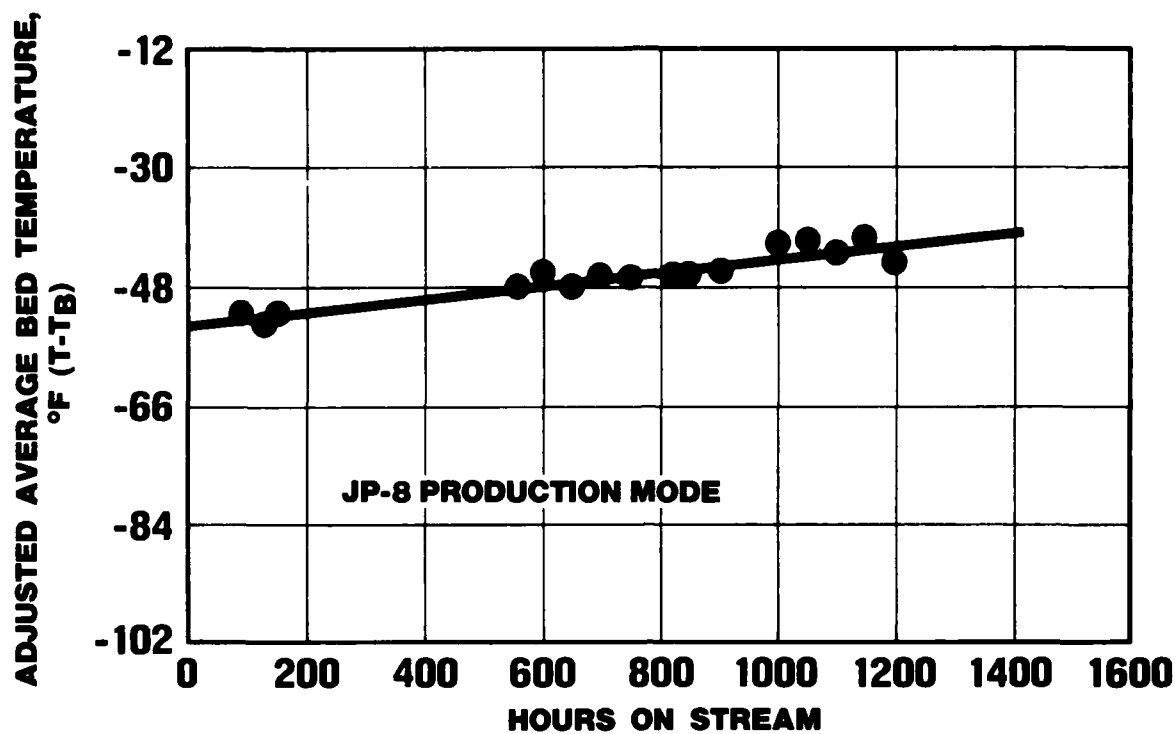
		<u>Run 2</u>	
Time on Stream, hours		<u>783</u>	<u>End of Run 1703</u>
Plug Number		1	2
Solids, wt-%	Quartz Chips	96.2	92.5
Emission, wt-ppm			
Fe	440	260	870
Ni	40	30	70
V	-	30	60
Ca	300	280	290
Mg	60	10	80
Mn	20	20	30
Cr	20	-	-
Sn	-	-	-
Cu	10	50	140
Zn	-	-	40
Ti	1600	1500	1900
Pb	-	-	-
Na	500	1000	1000
Mo	-	30	30
Co	210	-	-
Si	Major	Major	Major
Al	4600	2300	5300
Ba	60	30	60
Sr	-	-	-
Zr	60	240	310
B	300	800	110
Carbon, wt-%		53.67	6.90
Sulfur, wt-%		5.12	

TABLE 21. FRESH FEED FILTER CAKES

Run 2

Time on Stream, hours	<u>783</u>	<u>End of Run 1703</u>
Molecular Weight	392	380
ASTM Ash, wt-%	0.22	0.50
Con. Carbon, wt-%	9.43	12.3
C <sub>5</sub> Insol., wt-%	21.3	23.5
C <sub>7</sub> Insol., wt-%	19.1	22.8
Toluene Insol., wt-%	6.12	7.12
Bromine Number	6.6 (Modified Method)	4.6
Carbon, wt-%	84.44	84.85
Hydrogen, wt-%	12.45	12.77
Sulfur, wt-%	1.25	1.70
Nitrogen, wt-%	0.52	0.524
Oxygen, wt-%	1.64	0.88 ± 0.06
Emission, wt-ppm		
Fe	780	54
Ni	9	4.8
V	86	13
Ca	180	6.9
Mg	0.11	1.4
Mn	25	1.6
Cr	5.0	0.51
Sn	33	0.99
Cu	61	2.5
Zn	100	10.6
Ti	9.7	6.7
Pb	7.5	0.78
Na	78	9.2
Mo	8.9	0.85
Co	2.2	-
Si	230	Diluent
Al	Diluent	3.4
B	50	0.78
Ba	1.7	1.6
Sr	-	-
Zr	0.36	-
Ash	2,780	709
Melting Point, °F		206*

\* Heavy material left on tip of thermometer which will not melt.



**FIGURE 5**  
**PARALLEL – FLOW HYDROCRACKING**  
**CATALYST ACTIVITY AND STABILITY**

## SECTION IV

### PLATFORMING OF A C<sub>7</sub>-300°F SHALE OIL NAPHTHA

As part of the Phase III program, a narrow boiling naphtha cut from the hydrocracking operations was catalytically reformed to obtain basic information on yields and octane, and to compare this shale-derived naphtha with petroleum stocks.

Shale oils generally have narrower boiling ranges, from about 400° to 1000°F, and contain less naphtha as compared to petroleum crudes. With this boiling range, shale oils readily lend themselves to production of diesel and jet fuels. However, high yields of good quality gasoline can be produced from shale oil depending on the refinery configuration.

The UOP Platforming<sup>®</sup> process is a proprietary catalytic reforming process developed by UOP. It can be used to produce an excellent petrochemical feed for BTX recovery, or produce a high octane blending component for gasoline production. A valuable by-product of these operations is the production of hydrogen. In this instance, Platforming was used to investigate the shale oil naphtha as a potential source of special motor fuel.

#### Pilot Plant Description

A schematic diagram of the pilot plant used for this operation is shown in Figure 6. Fresh feed with recycle hydrogen is fed over the catalyst. The reactor effluent is condensed and the gas and liquid separated. The gas is recycled back to the reactor while the propane and heavier liquid is debutanized. The hydrogen produced in the process is removed continuously through a pressure regulator, measured and analyzed. The debutanized C<sub>5</sub>+ product is similarly weighed and analyzed.

Present commercial Platforming catalysts comprise extruded or spherical alumina promoted with Group IV, VII and VIII metals. A commercially proven UOP Platforming catalyst designated Rx-320 was employed in this study.

#### Feedstock

The Platforming naphtha feed was prepared by fractionating the hydrocracked product from the Phase II operations in two steps to remove the 300°F+ heavies and the C<sub>6</sub>- light front end to yield essentially 10 gallons of a C<sub>7</sub> to 300°F product. Inspections of this product are shown in Table 22.

This 58.5 °API gravity naphtha contained about 91 vol-% paraffins plus naphthenes, 1 vol-% olefins and 8 vol-% aromatics. The clear Research octane number was about 55. The nitrogen content was acceptable at <0.1 ppm, but the 110 ppm sulfur content and the 1% olefins were outside the normal specifications for Platformer feedstock. The high sulfur content was a result of the sulfur addition experiments in the hydrocracking program.

A mild hydrotreating operation was used to prepare the Platformer® feed. The operating conditions were typical of those required to hydro-treat a petroleum-derived naphtha. Following this hydrotreating step, the total product was fractionated to reduce the 95% and end points to about 255° and 298°F, respectively. The analysis of the Platformer feed is shown in Table 23. The sulfur and nitrogen contents are well below the levels required for current Platforming operations. The aromatics content has been reduced to about 5 vol-%. A detailed GC analysis of this material is given in Table 24.

#### Operating Conditions

Process conditions used in this study are comparable to those commercially employed for reforming petroleum naphtha. The base conditions selected for reference represent those employed commercially for

UOP's "State-of-the-Art" design of Continuous Platforming units. The nomenclature adopted to relate the actual operating conditions to these base conditions are as follows:

		<u>Written as</u>
Temperature	T-T (base), °C	T-T <sub>B</sub>
Pressure	P-P (base), psi	P-P <sub>B</sub>
Space Velocity	LHSV/LHSV (base)	L/L <sub>B</sub>
Hydrogen/Feed Ratio	$\frac{H_2/\text{Feed}}{H_2/\text{Feed (base)}}$	H/H <sub>B</sub>

This operation covered a range of temperatures from 70°F below to 20°F above the base temperature to obtain a yield-octane relation for this feed. The other operating conditions were:

Pressure	P-P <sub>B</sub> , psi	0
Space Velocity	L/L <sub>B</sub>	2
Hydrogen/Feed Ratio	H/H <sub>B</sub>	2.5

#### Yield-Octane Study

The Platformer product analyses with Research Octane numbers from 90 to 104 are given in Table 25. Product aromatic contents range from about 50 vol-% at 90 RONC to about 79 vol-% at 104 RONC. The product octanes responded very well to lead addition. There is an 8.5 octane increase in the product from the lowest octane operation to a 5.0 increase at the highest octane.

The product yield data are related to octane level in Figures 7, 8 and 9. The C<sub>5</sub> plus liquid yield varied linearly from 85 vol-% at 89 RONC to 70 vol-% at 104 RONC. At the highest operating severity there is an indication that the hydrogen yield (Figure 8) is leveling off.

Overall, the data show this shale oil naphtha cut to be an excellent Platformer feedstock that will give yields comparable to petroleum derived feeds when reformed to octanes ranging from 90 to 104 RONC.

## Special Gasoline Preparation

The individual products from this Platforming operation were blended to make a larger sample which was subsequently used to make a Special Grade, Class B volatility, gasoline. The analyses of this sample, as reported in Table 26, show a 47.2 °API gravity material having a Research octane number of 95.5.

To meet all the Class B volatility specifications, calculations showed it would be necessary to blend together 60 vol-% of the Platformate® blend, 30 vol-% of a C<sub>5</sub>-C<sub>6</sub> cut previously distilled out from the hydro-cracked shale oil naphtha product, and 10 vol-% of butanes. For practical considerations in the laboratory, the 10 vol-% of butanes was not blended with the liquids noted above.

An analysis of the C<sub>5</sub>-C<sub>6</sub> fraction having a Research octane number of 70.5 is given in Table 27.

The actual gasoline blend sent to the USAF consisted of 2:1 volume blend of Platformate and the C<sub>5</sub>-C<sub>6</sub> cut. Analyses of this blended gasoline are given in Table 28 and show that this gasoline meets all the chemical and antiknock requirements as outlined in Federal Specification VVG-1690B, July 1, 1978. A clear Research octane number of 87.2 was determined for this blend. A detailed isomer distribution analysis is given in Table 29.

The final Special Grade gasoline blend calculated by adding the equivalent of 10 vol-% butanes to the blended gasoline is shown in Table 30. This blend does not meet the Class B volatility specs for vapor pressure and TVL at 20°C but falls between the Class B and C gasolines. A slight adjustment in butane concentration would be sufficient to bring the gasoline either to a Class C or B volatility.

## Conclusions

Naphtha derived from hydrocracking shale oil can be catalytically reformed to yield high octane gasoline blending components. The C<sub>5</sub> plus

liquid yield varied linearly from 85 vol-% at 89 RONC to 70 vol-% at 104 RONC. Overall, this shale oil naphtha cut proved to be an excellent Platformer feed and gave yields comparable to petroleum-derived naphtha.

TABLE 22. NAPHTHA SAMPLE FROM HYDROCRACKING

<u>Analysis</u>		<u>GLC</u>	<u>Wt-%</u>
API Gravity at 60°F	58.5	<u>i</u> -C <sub>4</sub>	-
Sp.Gr. at 60°F	0.7447	<u>n</u> -C <sub>4</sub>	-
Distillation (D-86), °F		<u>i</u> -C <sub>5</sub>	-
IBP	217	<u>n</u> -C <sub>5</sub>	-
5%	224	2-MP	-
10%	227	3-MP	-
20%	230	2,2 DMB	-
30%	234	2,3 DMB	-
40%	240	<u>n</u> -C <sub>6</sub>	-
50%	246	C <sub>7</sub> P	16.72
60%	250	C <sub>8</sub> P	22.00
70%	256	C <sub>9</sub> P	14.49
80%	266	C <sub>10</sub> P	2.45
90%	280	C <sub>11</sub> P	
95%	293		
EP	338	C-C <sub>5</sub>	-
% Over	99.0	MCP	-
% Botts.	1.0	C-C <sub>6</sub>	0.02
		C <sub>7</sub> n	11.96
Sulfur, ppm	110.5	C <sub>8</sub> n	13.90
Nitrogen, ppm	<0.1	C <sub>9</sub> n	8.15
Oxygen, ppm	117	C <sub>10</sub> n	0.91
		C <sub>11</sub> n	
Carbon, wt-%	82.01		
Hydrogen, wt-%	14.35		
Mercaptan, ppm	0.5	Benzene	0.0
FIA, vol-%			
A	7.8	Toluene	2.9
O	1.1	C <sub>8</sub> arom	4.8
P + N	91.1	C <sub>9</sub> + arom	0.7
		Total	8.4
RON, Clear (micro)	54.6		
		Olefins	1.0

TABLE 23. HYDROTREATED PLATFORMER FEEDSTOCK

API Gravity at 60°F	62.0
Sp. Gr. at 60°F	0.7313
Distillation, (D-86), °F	
IBP	194
5%	204
10%	208
20%	214
30%	216
40%	220
50%	224
60%	227
70%	232
80%	238
90%	248
95%	254
EP	298
% Over	99.0
Molecular Weight	104
Sulfur, ppm	<0.1
Nitrogen, ppm	0.20
Carbon, wt-%	83.38
Hydrogen, wt-%	15.04
Chloride, ppm	4.4
Oxygen, ppm	<10
Mercaptan Sulfur, wt-%	0.0001
Lead, ppb	<20
Arsenic, ppb	1.4
Bromine Index	131.7
RON, Clear (micro)	56.4
PONA, vol-%	
P	61
O	0
N	34
A	5
FIA, vol-%	
A	5.5
O	-
P + N	94.5

TABLE 24. COMPONENT ANALYSIS OF HYDROTREATED PLATFORMER FEEDSTOCKS

<u>GC Analysis, Wt-%</u>			
Aromatics		ECP	2.59
Toluene	3.8	2,5-DMH	1.42
EB	0.5	2,4-DMH	1.48
p-Xylene	0.5	1-t-2-C-4-t-MCP	1.73
m-Xylene	1.1	1-t-2-C-3-t-MCP	0.92
o-Xylene	0.4	3,3-DMH	0.21
Total Aromatics	6.3	1,1,2-TMCP	0.41
Paraffins and Naphthenes		2-M-3-DP + 2,3-DMH	1.07
1-C <sub>5</sub>	0.44	1-c-2-t-4-t-MCP	0.53
n-C <sub>5</sub>	0.39	1-c-2-t-3-t-MCP	0.34
2,2-DMB	0.02	2-MH + 3-M-3-EP	5.94
Cyclo C <sub>5</sub>	0.02	1-c-2-c-4-5-MCP + 4-MH + 3,4-DMH	3.40
2,3-DMB	0.17	3-EH + 3-MH + 1,1-DMCH	6.68
2-MP	1.27	1-t-4-DMCH + 1-C-3-DMH	2.28
3-MP	0.85	1-MC-3-ECP	2.02
n-C <sub>6</sub>	1.22	1-M-t-3-2-ECP + 1-M-1-ECP	2.90
MCP	0.95	1-C-2-C-3-t-MCP + 1-t-2-DMCH	1.04
2,2-DMP	0.05	1-t-3-DMCH + 1-c-4-DMCH	1.89
2,4-DMP	0.19	IPCP	0.17
Cyclo C <sub>6</sub>	0.21	n-O	4.71
3,3-DMP	0.09	1-M-c-2-ECP	0.54
1,1-DMCP	0.44	1-c-2-DMCH	0.46
2-MH	6.65	ECH + n-P-c-P	1.45
2,3-DMP	1.58	C <sub>9</sub> Naphthenes	2.23
1-cis-3-DMCP	2.61	C <sub>9</sub> Paraffins	3.71
3-MH	7.03	Total P + N	93.7
1-t-3-DMCP	1.91		
1-t-2-DMCP	2.14		
3-EP	0.57		
n-C <sub>7</sub>	6.76		
1-C-2-DMCP	1.48		
MCH	4.77		
1,1,3-TMCP	0.94		
2,2-DMH	0.23		

See Table 29 for compound definitions.

TABLE 25. PLATFORMER PRODUCT ANALYSES

Period	1	2	3	4	5	6	7	8	9
API Gravity at 60°F	50.5	49.6	47.8	47.4	45.3	44.3	40.6	40.2	50.9
Sp. Gr. 60/60°F	0.7775	0.7813	0.7892	0.7909	0.8003	0.8049	0.8222	0.8241	0.7758
Distillation (D-86), °F									
IBP	129	144	136	136	128	122	120	121	140
5%	175	178	166	165	158	154	154	158	178
10%	188	190	182	180	176	173	177	178	191
20%	206	206	201	200	200	199	208	209	206
30%	217	217	216	215	217	218	230	232	218
40%	226	225	226	227	230	232	242	244	226
50%	234	234	236	238	241	243	250	252	233
60%	242	242	246	252	251	252	256	258	240
70%	251	253	256	259	260	260	264	265	250
80%	264	265	268	268	270	270	273	274	262
90%	282	282	284	283	285	283	286	285	280
95%	296	295	300	296	300	299	300	300	298
EP	350	328	331	337	336	338	346	356	316
% Over	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0
% Bottoms	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
FIA, vol-%									
A	50.2	52.4	57.2	58.9	64.8	67.1	77.7	79.2	49.1
O	1.3	1.3	1.3	1.3	1.3	1.4	1.1	.9	1.6
P + N	48.5	46.3	41.5	39.8	33.9	31.5	21.2	19.9	49.3
Octane Number									
RONC	90.2	91.2	95.2	95.9	98.2	99.8	103.7	104.3	88.7
RON + 3 TEL	98.7	99.3	102.3	102.0	104.2	104.7	107.6	109.2	97.6
MON	80.6	81.2	84.4	86.8	87.3	88.5	92.0	92.4	79.5

TABLE 26. PLATFORMER PRODUCT BLEND

API Gravity at 60°F	47.2
Sp. Gr. 60/60°F	0.7918
Distillation (D-86), °F	
IBP	137
5%	175
10%	189
20%	207
30%	221
40%	230
50%	238
60%	247
70%	257
80%	270
90%	287
95%	306
EP	351
% Over	97.5
% Bottoms	1.0
% Loss	1.5
Dry Point, °F	320
RON Clear	95.5
MON Clear	84.8
Reid Vapor Pressure, psi	3.3

TABLE 27. C<sub>5</sub>-C<sub>6</sub> FRACTION

API Gravity at 60°F	77.3	GC	Wt-%
Sp. Gr. 60/60	0.6777	<u>i</u> -C <sub>4</sub>	trace
Distillation (D-216), °F		<u>n</u> -C <sub>4</sub>	0.1
IBP	120	<u>i</u> -C <sub>5</sub>	7.6
5%	130	<u>n</u> -C <sub>5</sub>	8.7
10%	134	2,2-DMB	0.3
20%	137	CP	0.6
30%	140	2,3-DMB	2.7
40%	144	2-MP	19.5
50%	148	3-MP	13.0
60%	152	<u>n</u> -C <sub>6</sub>	16.9
70%	155	MCP	13.1
80%	159	CH	1.9
90%	166	Bz	0.9
95%	174	C <sub>7</sub> +	14.6
EP	240	Olefins	0.1
% Over	99.0		
% Bottoms	1.0		
Nitrogen, ppm	0.13		
Sulfur, ppm	32		
Vapor Press., psi	7.7		
RON Clear	70.5		
MON Clear	68.8		

TABLE 28. GASOLINE BLEND

API Gravity at 60°F	56.2	Existent Gum, mg/100 mL	1
Sp. Gr. 60/60°F	0.7539	Unwashed Gum, mg/100 mL	1
Distillation (D-86), °F		Oxidation Stability, min.	>1200
IBP	135		
5%	151	RON Clear	87.2
10%	159	MON Clear	79.8
20%	170	R+M/2	83.5
30%	180		
40%	192	Water and	
50%	206	Sediment, vol-%	<0.005
60%	223		
70%	244	Benzene, vol-%	1.2
80%	261	Phosphorus (unleaded),	
90%	282	g/gal	<0.0003
95%	306		
EP	323		
% Over	98.0		
% Loss	1.0		
% Bottoms	1.0		
Dry Point, °F			
Carbon, wt-%	85.86		
Hydrogen, wt-%	13.70		
Nitrogen, ppm	0.3		
Oxygen, ppm	352		
Sulfur			
(unleaded), ppm	5.6		
Reid Vapor Pres., psi	5.1 (35.16 kPa)		
FIA, vol-%			
A	39.0		
O	1.1		
P + N	59.9		
Cu Strip Corrosion	1A		
Antiknock Content			
Lead (unleaded)	<0.01 g/gal		
Manganese (unleaded)	<0.1 ppm		
Temperature, °C, min.			
at V/L Ratio = 20	71.3		

TABLE 29. GASOLINE BLEND

Complete Isomer Distribution

	<u>Wt-%</u>
<u>Aromatics</u>	
Benzene	1.5
Toluene	18.5
Ethylbenzene	2.7
p-Xylene	4.7
m-Xylene	9.6
o-Xylene	5.9
C <sub>9</sub> + Aromatics	4.2
Total A	46.9
<u>olefins</u> (Total)	1.0
<u>Paraffins and Naphthenes</u>	
1. Propane	
2. Isobutane	
3. n-Butane	0.10
4. Isopentane	4.49
5. n-Pentane	4.04
6. 2,2-Dimethylbutane	0.14
7. Cyclopentane	0.23
8. 2,3-Dimethylbutane	0.56
9. 2-Methylpentane	4.30
10. 3-Methylpentane	3.22
11. n-Hexane	5.18
12. Methylcyclopentane	3.03
13. 2,2-Dimethylpentane	0.59
14. 2,4-Dimethylpentane	1.19
15. 2,2,3-Trimethylbutane	0.10
16. Cyclohexane	0.54
17. 3,3-Dimethylpentane	0.47
18. 1,1-Dimethylcyclopentane	0.11
19. 2-Methylhexane	3.93
20. 2,3-Dimethylpentane	1.28
21. 1,2,3-Dimethylcyclopentane	0.10
22. 3-Methylhexane	4.50
23. 1-trans-3-Dimethylcyclopentane	0.15
24. 1-trans-2-Dimethylcyclopentane	0.16
25. 3-Ethylpentane	0.44
26. 2,2,4-Trimethylpentane	0.02
27. n-Heptane	3.50
28. 1-cis-2-Dimethylcyclopentane	0.02
29. Methylcyclohexane	0.03
30. 1,1,3-Trimethylcyclopentane	0.02
31. 1,2-Dimethylhexane	0.25
32. 2-Methylcyclohexane	0.04
33. 1,3-Dimethylhexane	0.38
34. 2,4-Dimethylhexane	0.70
35. 2,3,4-Trimethylpentane	0.01
36. 1-trans-2-cis-4-Trimethylcyclopentane	

TABLE 29. GASOLINE BLEND (Continued)

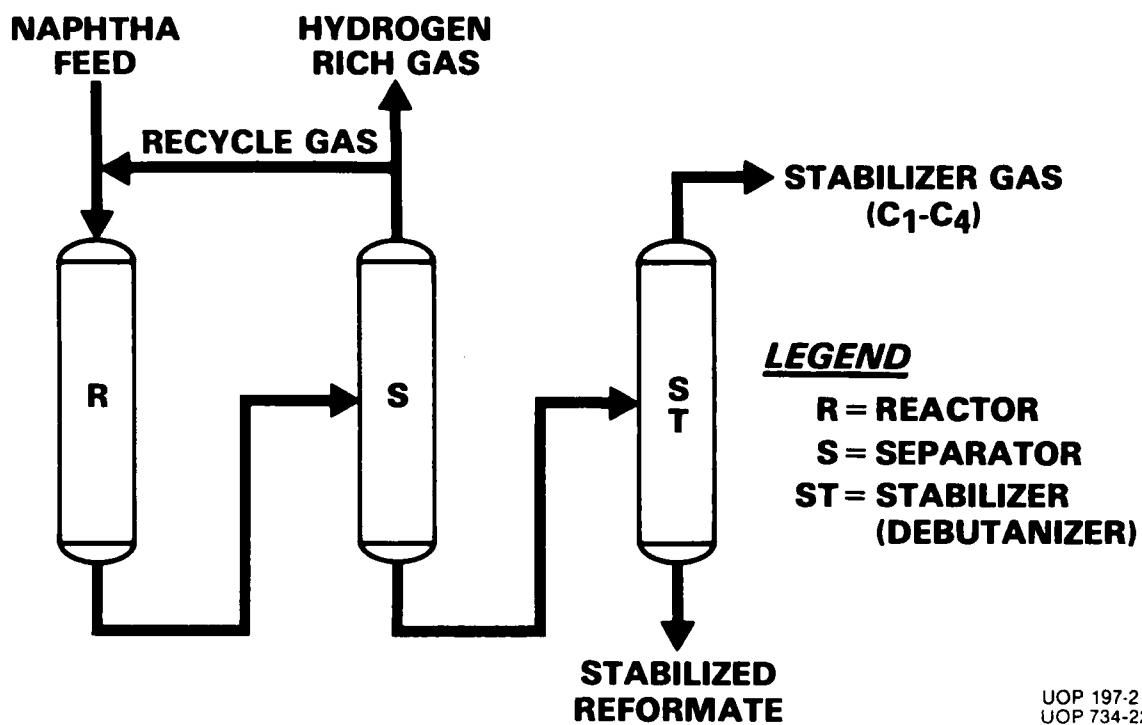
Paraffins and Naphthenes (Cont.)

37.	1- <u>trans</u> -2- <u>cis</u> -3-Trimethylcyclopentane	0.01
38.	3,3-Dimethylhexane	0.27
39.	2,3,4-Trimethylpentane	0.03
40.	1,1,2-Trimethylcyclopentane	0.01
41.	2,3,3-Trimethylpentane	0.03
42.	2-Methyl-3-ethylpentane	
43.	2,3-Dimethylhexane	0.51
44.	1- <u>cis</u> -2- <u>trans</u> -4-Trimethylcyclopentane	
45.	1- <u>cis</u> -2- <u>trans</u> -3-Trimethylcyclopentane	
46.	2-Methylheptane	1.52
47.	3-Methyl-3-ethylpentane	
48.	1- <u>cis</u> -2- <u>cis</u> -4-Trimethylcyclopentane	
49.	4-Methylheptane	1.07
50.	3,4-Dimethylhexane	
51.	3-Ethylhexane	
52.	3-Methylheptane	2.35
53.	1,1-Dimethylcyclohexane	
54.	1- <u>trans</u> -4-Dimethylcyclohexane	
55.	1- <u>cis</u> -3-Dimethylcyclohexane	
56.	1-Methyl- <u>cis</u> -3-ethylcyclopentane	0.03
57.	1-Methyl- <u>trans</u> -3-ethylcyclopentane	
58.	1-Methyl- <u>trans</u> -2-ethylcyclopentane	0.07
59.	1-Methyl-1-ethylcyclopentane	
60.	1- <u>cis</u> -2- <u>cis</u> -3-Trimethylcyclopentane	
61.	1- <u>trans</u> -2-Dimethylcyclohexane	
62.	1- <u>trans</u> -3-Dimethylcyclohexane	
63.	1- <u>cis</u> -4-Dimethylcyclohexane	
64.	Isopropylcyclopentane	
65.	<u>n</u> -Octane	1.71
66.	1-Methyl- <u>cis</u> -2-ethylcyclopentane	
67.	1- <u>cis</u> -2-Dimethylcyclohexane	0.04
68.	Ethylcyclohexane	0.02
69.	<u>n</u> -Propylcyclopentane	
	C <sub>9</sub> Naphthenes	0.09
	C <sub>9</sub> Paraffins	0.39
	C <sub>10</sub> Naphthenes	0.13
	C <sub>10</sub> Paraffins	
	C <sub>11</sub> Naphthenes	
	C <sub>11</sub> Paraffins	
	C <sub>12</sub> P + N	
	Total P + N:	52.1

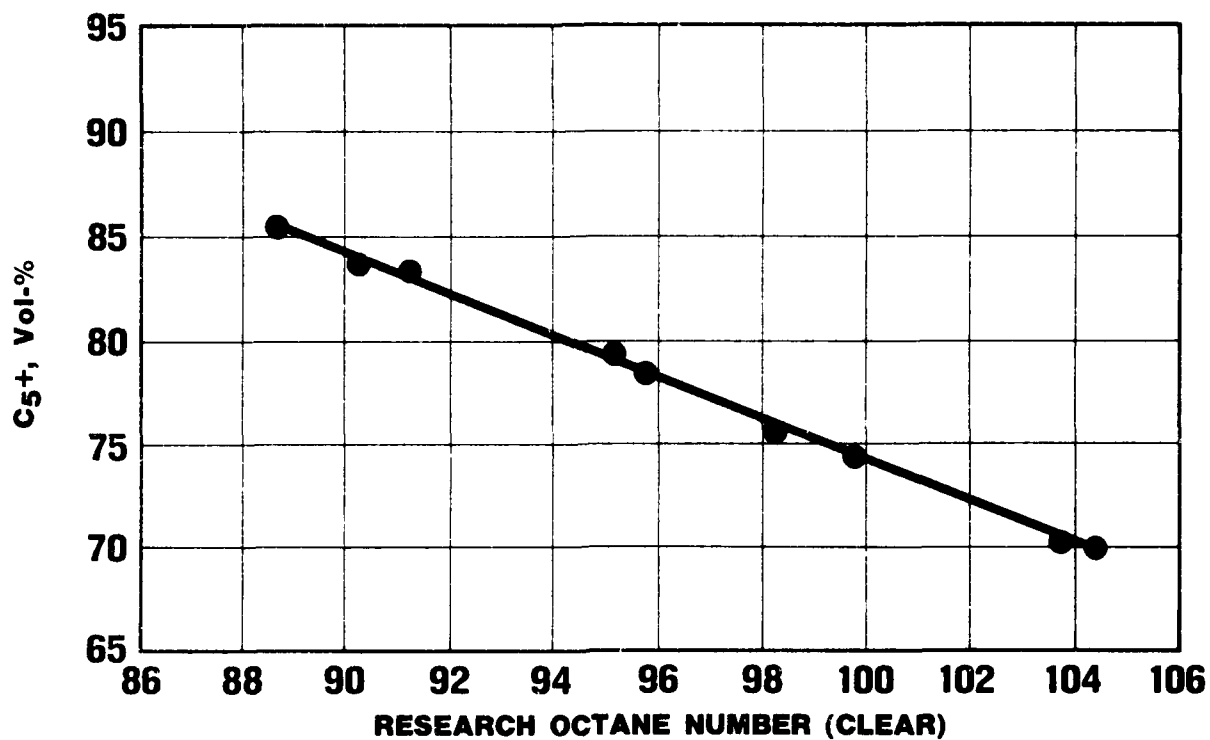
Totals

TABLE 30. SPECIAL GASOLINE

API Gravity at 60°F	60.5
Sp. Gr. 60/60°F	0.7370
Distillation (D-86), °F	<u>°F</u>
IBP	96
10%	125
30%	168
50%	195
70%	235
90%	278
EP	306
RON Clear	87.9
MON Clear	80.8
$\frac{R + M}{2}$	84.4
	<u>psi</u>
Reid Vapor Pressure	11.1
Temperature, °C min at V/L Ratio = 20	53.0

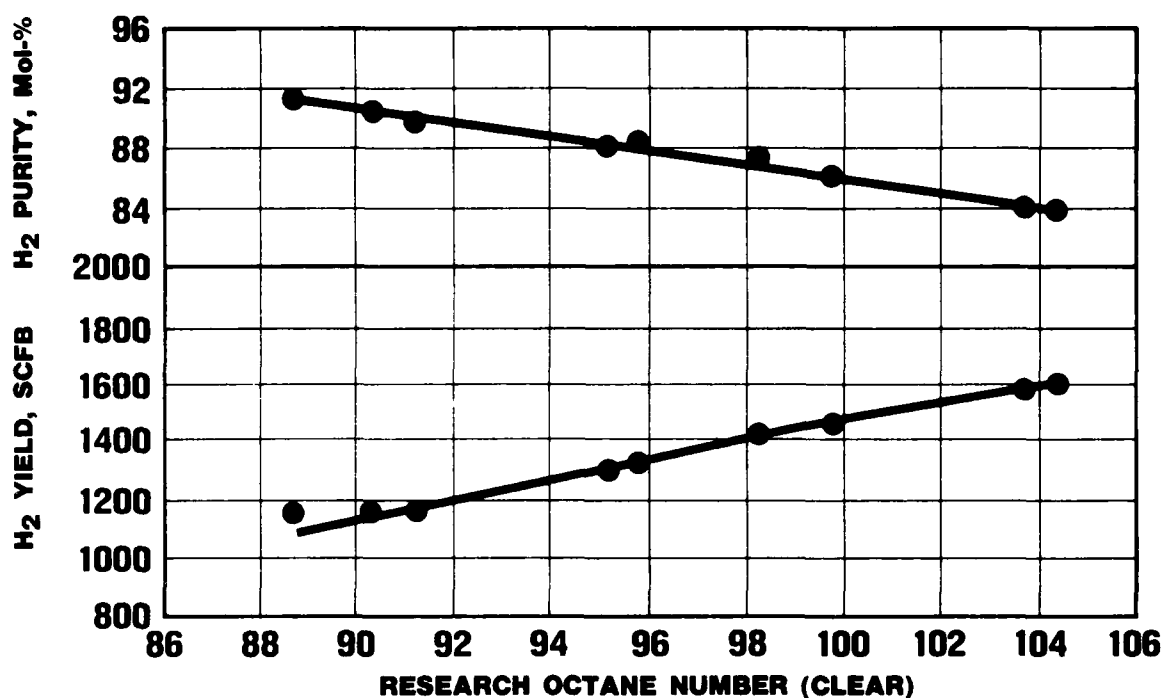


**FIGURE 6**  
**NAPHTHA REFORMING PILOT PLANT**



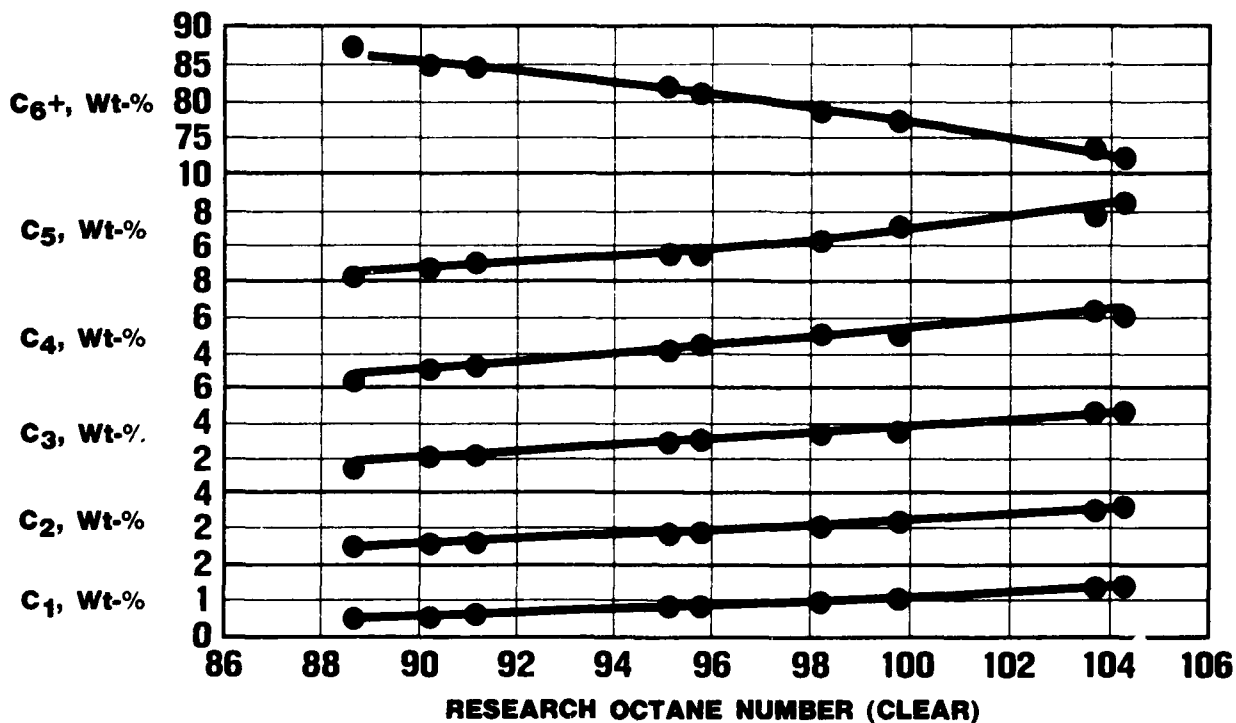
UOP 734-20

**FIGURE 7**  
**PLATFORMING YIELD – OCTANE STUDY**  
**OCCIDENTAL SHALE OIL**  
**LIQUID AND HYDROGEN YIELDS**



UOP 734-21

**FIGURE 8**  
**PLATFORMING YIELD – OCTANE STUDY**  
**OCCIDENTAL SHALE OIL**  
**LIQUID AND HYDROGEN YIELDS**



UOP 734-19

**FIGURE 9**  
**PLATFORMING YIELD — OCTANE STUDY**  
**OCCIDENTAL SHALE OIL**

## SECTION V

### ARSENIC MANAGEMENT STUDIES

Shale oils produced by current retorting operations contain arsenic in such concentrations that it deserves special attention. Two approaches to the shale oil arsenic management problem have been investigated in this program:

1. Crude shale oil arsenic solubilization
2. Deposited arsenic passivation or extraction.

#### Shale Oil Arsenic Solubilization

The first hypothesis investigated involved converting the arsenic in the raw shale oil to a water soluble compound. This might be accomplished by injecting a reagent downstream of the retort into the oil-water mixture. With intimate mixing of the reagent, oil and water may convert the arsenic into water soluble compounds. After the two phases are allowed to coalesce, the water phase is drained off leaving a shale oil with reduced arsenic content. The water containing arsenic could then be further treated, if necessary, to render it environmentally safe.

Desalted Occidental shale oil with 19 ppm arsenic was utilized as the hydrocarbon source for a series of experiments attempting to convert arsenic into water soluble compounds. For these experiments, the water, reagent and shale oil were intimately contacted utilizing a shear-type mixer. Each test was performed by mixing the oil and water for 15 minutes at about 95°C (200°F). The type of emulsion formed while adding various reagents was observed, and the arsenic level left in the oil was measured after each test.

A summary of results is shown in Table 31. Arsenic solubilization ranged from 13 to 52%. The removal of arsenic was probably accomplished by

the formation of an insoluble material that is associated with the emulsion. The use of a wide range of reagents along with shear mixing to effect water solubilization of arsenic from shale oil does not appear to be very promising.

#### Arsenic Passivation and Extraction

The high concentration of arsenic in the raw shale oil and its removal and containment on the first-stage hydrotreater catalyst poses some special handling problems. Before arsenic-laden catalysts can be disposed of as non-hazardous wastes, the aqueous solubility of arsenic as measured by the EPA Toxicity test must be reduced to less than 5 ppm. In an effort to meet this requirement for safe disposal, the following objectives were considered:

1. Ascertain the composition of arsenic-containing species on used catalyst.
2. Determine the arsenic solubility of aqueous extracts of used catalysts.
3. Evaluate methods of passivating soluble arsenic.
4. Determine the effect of various gases on arsenic volatility.
5. Evaluate the extraction behavior of arsenic from untreated and thermally treated used catalysts using various solvents.
6. Determine the conditions for complete dissolution of used catalysts.

#### Experimental Procedure

Samples of spent catalysts were thermally treated by spreading the catalyst pills inside a 1-inch silica tube. Three thermocouples were placed at the ends and middle of the catalyst bed. The catalyst sample was held in

place by tufts of quartz wool. Rubber stoppers fitted with glass tubes allowed controlled atmospheres to be passed through the sample gas flow as adjusted to 600 mL/min.

Heating was accomplished by a 30 cm-long split tube furnace. Once the desired temperature had been reached, the silica tube containing the sample was inserted. The furnace temperature was held to within  $\pm 10^{\circ}\text{C}$ . Cooling was achieved by removing the apparatus from the furnace. When cool, the catalyst was removed from the tube. The sample was analyzed for arsenic and sulfur.

Thermally treated and as-received samples were extracted in various solvents. Five gram samples were added to Erlenmeyer flasks containing 200 mL of extractant and shaken on a wrist shaker for 3 hours. The resulting slurry was filtered and washed. The catalyst residue and filtrate were analyzed for arsenic and sulfur.

#### Elemental Analysis

The elemental analyses of spent catalyst beds removed from two first-stage hydrotreating pilot plant reactors show that the arsenic concentration declines rapidly downward through the bed. As shown in Table 32, iron exhibits a similar profile while the remaining elements are fairly evenly distributed. The major difference between the two catalysts is the much higher arsenic level on the used catalyst designated as "Catalyst 2". The relative concentrations of the arsenic and iron throughout the catalyst bed are not significantly different.

An identification of the arsenic compounds present on the catalyst was considered necessary in order to determine the best methods to either fix the leachable arsenic by further chemical reaction or convert the arsenic into a highly soluble form. X-ray diffraction patterns obtained for the two samples were analyzed and the results are summarized in Table 33. The peak positions were calculated, and a manual search was made of the powder diffraction files in order to determine which compounds were present.

The  $\gamma$ - $\text{Al}_2\text{O}_3$  of the catalyst base is a major component in both samples. Trace levels of  $\alpha$ -quartz and boehmite were also detected. The rest of the standard patterns listed fit the sample patterns well, but the actual components present may have slightly different compositions.

Both samples contain a major phase similar to pyrrhotite  $[\text{Fe}_{(1-x)}\text{S}]$ , where  $x \leq 0.1$ . A slight increase in sulfur content would lead to a mixture of pyrrhotite and pyrite ( $\text{FeS}_2$ ). There is evidence of pyrite in the sample designated "Catalyst 1".

$\text{Co}_{0.84}\text{Ni}_{0.16}\text{As}_{1.04}$  is the cobalt analog of niccolite  $(\text{NiAs})_1$ . Their patterns are similar. The peaks in the pattern more closely match the former ( $\text{Co}_{0.84}\text{Ni}_{0.16}\text{As}_{1.04}$ ); however, the actual compound present may have a formula somewhere between the two arsenides.

Although some of the peaks for the two used catalysts match the pattern of  $\text{Cu}_{24}\text{As}_{12}\text{S}_{31}$ , there was no copper detected in the elemental analysis. It is possible a similar compound was present with other metals substituted for the copper.

The chloroform-washed samples were subjected to a modified EPA Toxicity test for arsenic. The modification in procedure was the use of 10 grams in place of 100 gram samples. As shown in Figure 10, the As solubility of the chloroform-washed catalyst appears to be a linear function of the As content of the catalyst. In order to meet the EPA limit, the catalyst would have to contain less than 0.2 wt-% As.

Metal salts were blended with the used catalyst, then heated in an inert atmosphere in an attempt to fix the arsenic as metal arsenides or metal arsenous sulfides. It was anticipated that conversion to these compounds would cause the arsenic to be less soluble; however, as shown in Figure 10, this proved not to be the case.

The EPA test was performed on several used catalysts that had been previously extracted with sulfuric and nitric acid solutions. The arsenic solubility was decreased; however, the arsenic level remaining on the

catalyst was still too great for direct disposal. As shown in Figure 10, in order to meet the EPA limit, it will be necessary to reduce the As content on the catalyst to about 0.5 wt-%.

If essentially all of the arsenic could be volatilized in a roasting process, arsenic collection would be feasible. Considering the relatively high vapor pressures of arsenic, arsenic sulfide and arsenic oxide, it appears that arsenic would be removed at elevated temperatures in either oxidizing, reducing, or neutral atmospheres.

As shown in Figure 11, the volatility of arsenic from spent catalyst was dependent upon temperature, residence time and atmosphere. It appears that a temperature of about 500°C (932°F) is required to break down the original arsenic minerals and to ensure adequate vapor pressure of volatile species. If the rate of arsenic volatilization can be increased, arsenic might be recovered by such a process.

Extractants were chosen to discern the state of arsenic present on the catalyst following thermal pretreatment.  $\text{H}_2\text{SO}_4/\text{FeCl}_3$  and  $\text{HNO}_3$  are strong oxidizing agents capable of oxidizing sulfide minerals. Sulfuric acid is a non-oxidizing acid which can solubilize sulfates and arsenates. Sodium sulfide forms complex anionic arsenous sulfides which are highly soluble.

Arsenic extraction results, from catalysts that were thermally oxidized at the severe conditions of 500°C in 5%  $\text{O}_2$ , were very similar. The data shown in Figure 12 indicate that the arsenic has probably been converted to an arsenate.

The data plotted in Figure 13 indicate that catalysts pretreated under rather neutral conditions, 25%  $\text{H}_2\text{O}/75\% \text{N}_2$ , were more effectively extracted with oxidizing acids than with the other leachants. The arsenous sulfide minerals are only beginning to be broken down at the highest temperature, 600°C (1112°F).

As shown in Figure 14, using  $\text{SO}_2$  in the thermal treatment step produces a different response to the extractants. At temperatures below 500°C, the

SO<sub>2</sub> atmosphere produced little change in the arsenic chemistry. At 500°C, SO<sub>2</sub> reacted slowly with carbon to form sulfur and CO<sub>2</sub> and converted the metal arsenous sulfides to more leachable forms. All of the extractants remove approximately the same level of arsenic.

None of the thermal pretreatments produced a material that allowed high levels of arsenic extraction. In the best case, about 80% of the arsenic was removed by a combination of thermal treatment and leach extraction. Increasing the leachant concentration to increase the arsenic extraction would result in considerable alumina dissolution.

An alternative approach to arsenic recovery utilized solution oxidation. Acid digestion of as-received used catalyst was performed in a stoichiometric quantity of sulfuric acid, assuming the catalyst composition to be entirely Al<sub>2</sub>O<sub>3</sub> with the following reaction:



The digestion was carried out under reflux for 8 hours. In order to obtain high recoveries of the elements, the reaction had to be carried out at a positive solution potential. This was accomplished by adding 3 wt-% HNO<sub>3</sub> to the sulfuric acid. As shown in Table 34, 90% recovery of arsenic was achieved with both the 10 and 20 wt-% sulfuric acid solutions. Only molybdenum was poorly recovered in this solvent; however, molybdenum can be recovered from the residue using other techniques. Digestion of thermally treated catalysts was not as effective in recovering arsenic as solution oxidation of the as-received used catalyst.

### Conclusions

1. Used catalysts from processing shale oil will contain higher levels of soluble arsenic than allowed by the EPA for non-hazardous disposal.
2. Much of the arsenic is present on the catalyst as thermally stable metal arsenides and metal arsenous sulfides.

3. It was not possible to fix or passivate the arsenic on the catalyst in an insoluble form by thermally treating the catalyst with or without additives.
4. Leachants, which do not dissolve excessive quantities of alumina, extract only about 20% of the arsenic from non-thermally treated catalysts.
5. Of the thermal treatments investigated, only dilute oxidizing atmospheres, 5% O<sub>2</sub> or less, at elevated temperatures,  $\geq 500^{\circ}\text{C}$ , for extended time result in appreciable arsenic volatilization. This indicates that arsenic is not present on the catalyst as a simple sulfide, oxide or metallic compound.
6. Increasingly severe thermal pretreatments allow up to 75% of the arsenic to be extracted by dilute leachants.
7. Both temperature and gas composition are important variables in converting the arsenic to a leachable form.
8. Results of toxicity tests on previously treated catalysts indicate that high extraction levels are necessary before the residue is acceptable.
9. Digestion of as-received spent catalyst requires a high solution potential in order to achieve good extractions.
10. Digestion of thermally oxidized catalysts yields poorer arsenic extractions than solution oxidation of the as-received catalysts.
11. Topics worthy of further investigation include the evaluation of different ratios of As, Fe, C and S on arsenic volatility and solubility; the recovery of arsenic by thermal means; the development of methods to recover arsenic from acidic solutions; and the determination of the minimum acid necessary to achieve good extractions of arsenic without excessive dissolution.

TABLE 31. SHALE OIL ARSENIC SOLUBILIZATION STUDY

Arsenic in Feed = 19 ppm

<u>Reagent</u>	<u>Observation</u>	<u>Arsenic in Oil, ppm</u>
10% KOH	Emulsion stable, broken by addition of isooctane/methanol.	10.8
10% H <sub>2</sub> SO <sub>4</sub>	No emulsion formed.	16.6
50% Acetic acid	Formed emulsion which slowly broke.	14.7
10% Na <sub>2</sub> S	Formed emulsion which did not break with isooctane/methanol treatment.	
	1) One hour at 220°C (430°F) under 100 ATM of N <sub>2</sub> -broke.	11.7
	2) Centrifuged at 7000 ppm, part of the emulsion broke.	9.1

TABLE 32. FIRST-STAGE HYDROTREATER, SPENT CATALYST ANALYSIS

Sample Location	Element, wt-%							
<u>Catalyst 1</u>	<u>Fe</u>	<u>C</u>	<u>N</u>	<u>S</u>	<u>H</u>	<u>As</u>	<u>Mo</u>	<u>Co</u>
Upper Section	6.3	10.4	0.47	9.3	1.6	2.4	+	+
Upper Middle	4.5	10.5	0.34	8.6	1.4	1.2	+	+
Middle Section	1.0	13.4	0.57	8.2	1.6	0.32	+	+
Lower Middle	0.4	13.3	0.59	7.8	1.4	0.12	+	+
Lower Section	0.4	14.1	0.67	7.5	1.3	0.07	+	+
<u>Catalyst 2</u>								
Top	6.0	9.11	3.9	6.2		8.4	+	+
Top Middle	3.7	10.2	0.43	6.4		5.6	+	+
Middle	1.9	10.1	0.43	5.7		3.4	+	+
Bottom Middle	1.0	10.2	0.85	5.8		1.6	+	+
Bottom	0.9	10.3	0.22	5.5		1.3	+	+

+ = Present.

TABLE 33. DIFFRACTION DATA ON USED CATALYSTS

<u>Compound Identification</u>	<u>Catalyst 1 Upper Section</u>	<u>Catalyst 2 Upper Section</u>
$\gamma\text{Al}_2\text{O}_3$	m	m
$\alpha\text{SiO}_2$	t	t
$\text{AlO}(\text{OH})$ Boehmite	t	
$\text{Fe}_{(1-x)}\text{S}$ Pyrrhotite	m	m
$\text{FeS}_2$ Pyrite		t
$\text{Co}_{0.84}\text{Ni}_{0.16}\text{As}_{1.04}$	t	m
$\text{Cu}_{24}\text{As}_{13}\text{S}_{31}$	t	m

m = major

t = trace

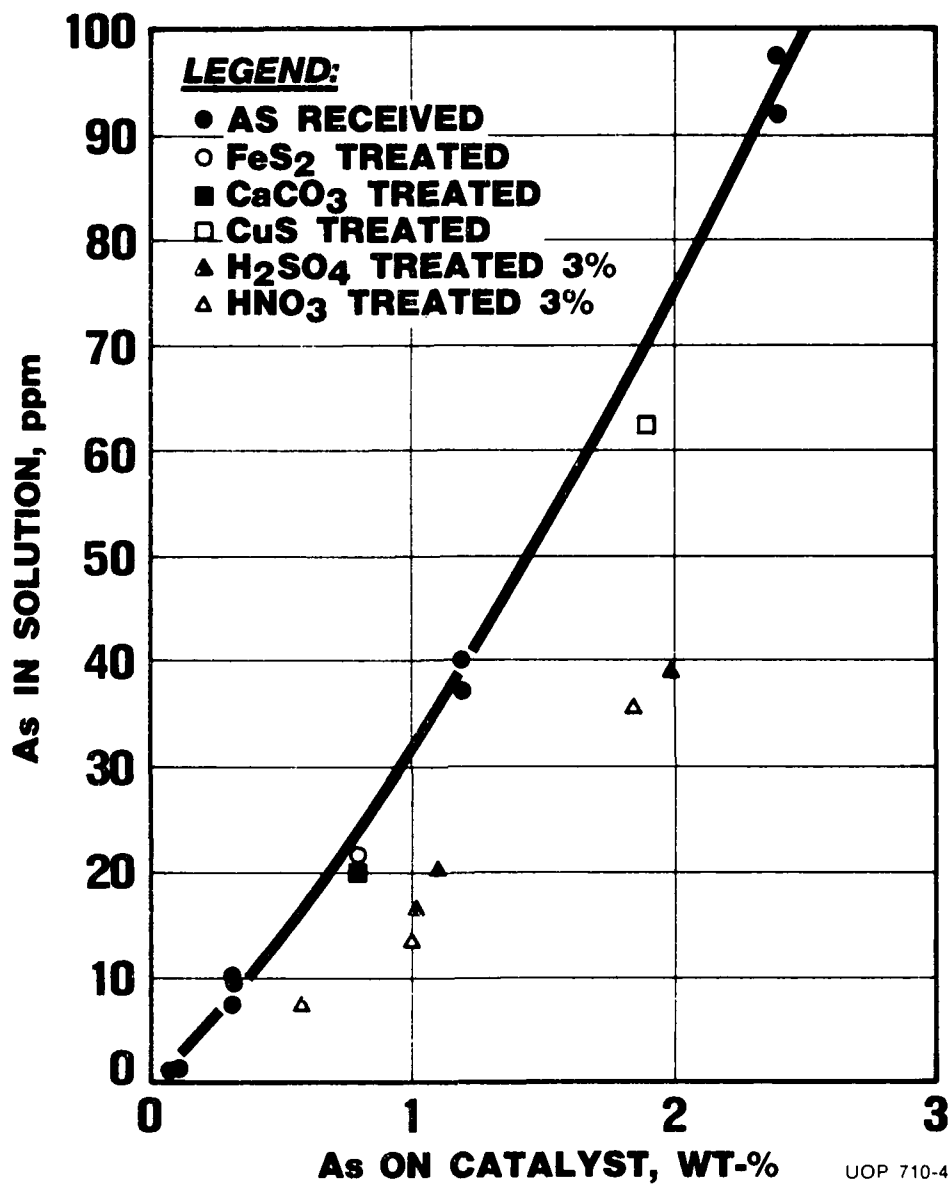
TABLE 34. DIGESTION OF USED CATALYST

Used Catalyst Analysis: Arsenic, wt-% 1.16

Digestion Solution		As Extraction, %
<u>H<sub>2</sub>SO<sub>4</sub>, wt-%</u>	<u>HNO<sub>3</sub>, wt-%</u>	
10	-	24
10	3	90
20	-	23
20	3	90
40	-	24
40	3	72

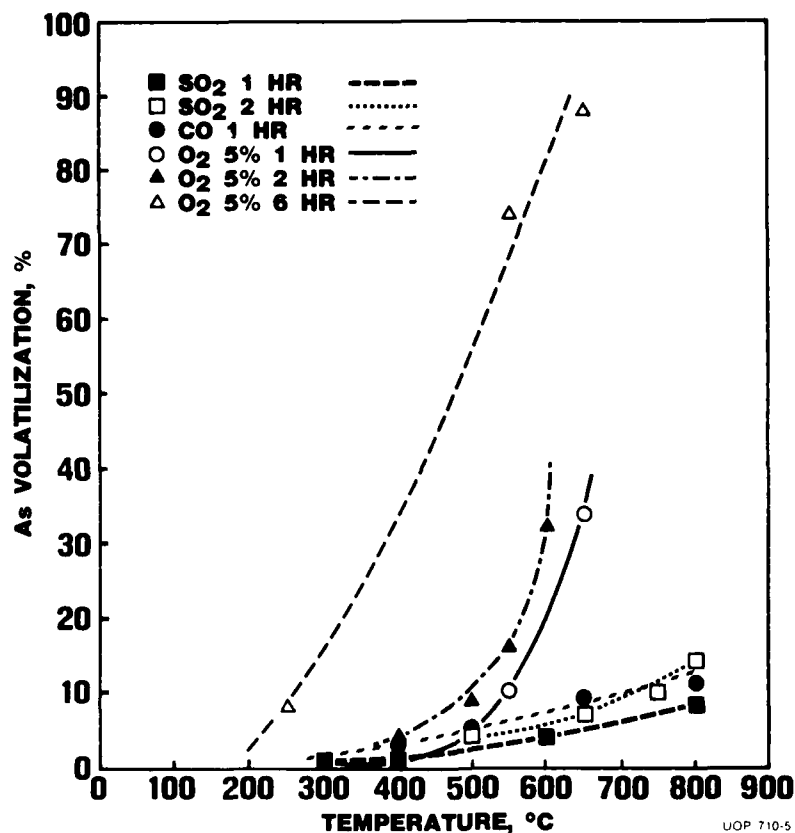
Thermally Treated Catalyst  
 Extracted in 40 wt-% H<sub>2</sub>SO<sub>4</sub>

Thermal Treatment			% As Removed		
<u>Temp., °C</u>	<u>Gas</u>	<u>Time, Hr</u>	<u>Volatilization</u>	<u>Extraction</u>	<u>Total Removal</u>
550	5% O <sub>2</sub>	6	69	50	74
650	5% O <sub>2</sub>	2	58	53	80
250	5% O <sub>2</sub>	6	9	74	76

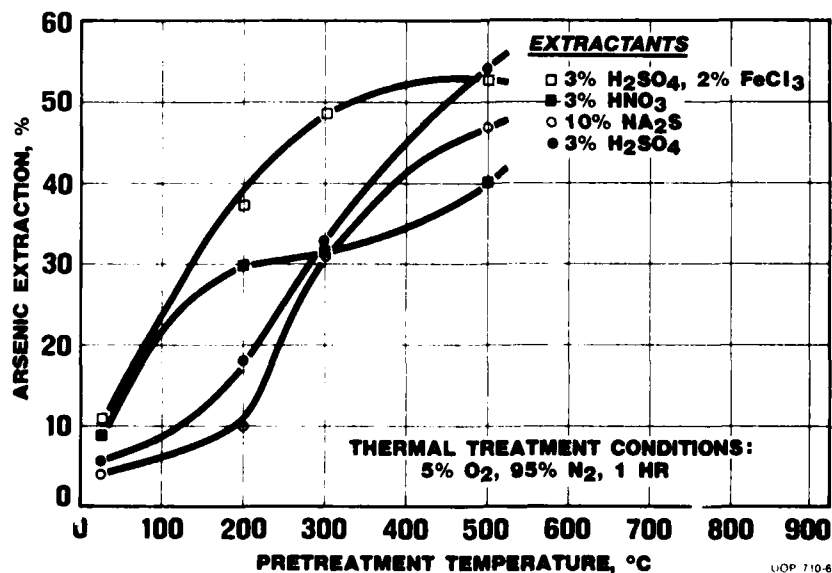


**FIGURE 10**

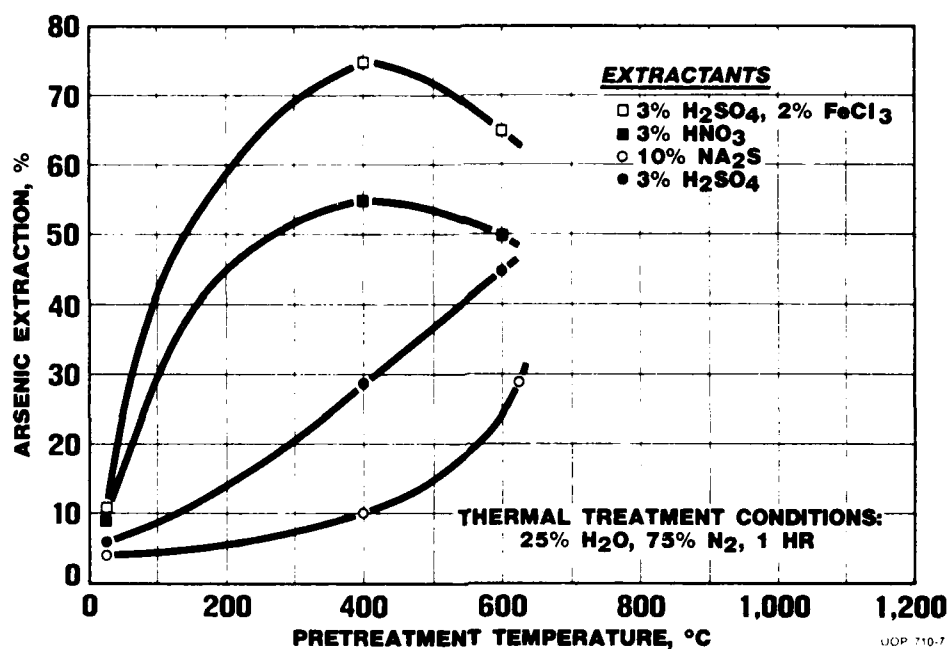
**SIMULATED EPA TOXICITY  
TEST ON USED CATALYST**



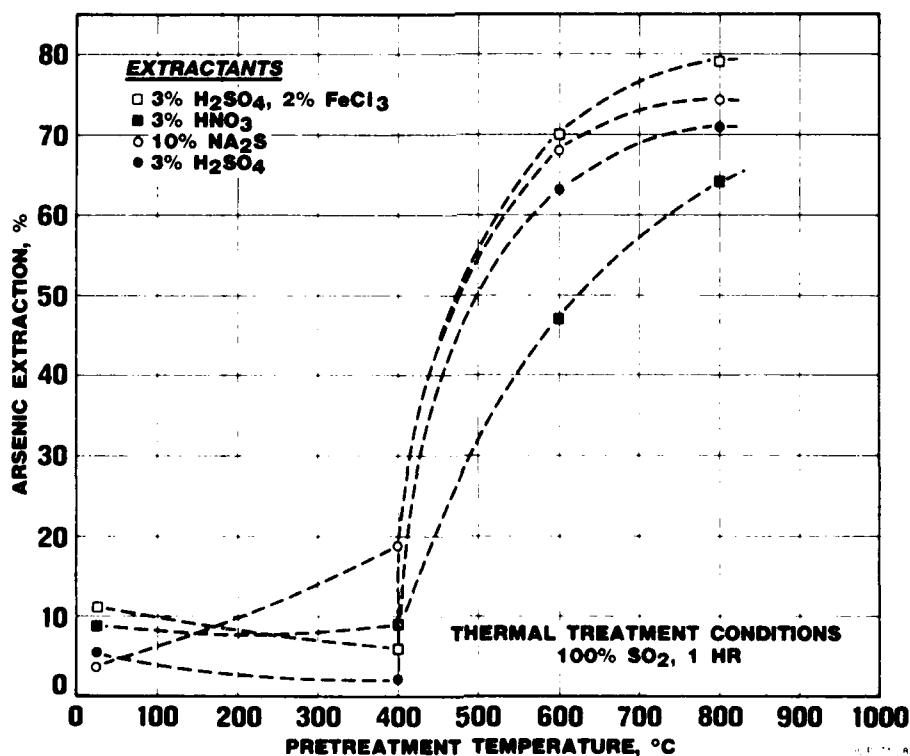
**FIGURE 11**  
**EFFECT OF THERMAL TREATMENT**  
**ON ARSENIC VOLATILIZATION**



**FIGURE 12**  
**EFFECT OF SEVERE OXIDATION**  
**ON ARSENIC EXTRACTION FROM**  
**USED CATALYST**



**FIGURE 13**  
**EFFECT OF MILD OXIDATION ON ARSENIC EXTRACTION FROM USED CATALYST**



**FIGURE 14**  
**EFFECT OF SULFUR TREATMENT ON ARSENIC EXTRACTION FROM USED CATALYST**

## SECTION VI

### FOULING

The Monirex® Fouling Monitor has been used to determine the thermal fouling properties of aged Occidental desalted shale oil, an Arabian Light Berri petroleum oil and blends of these oils. In addition, the thermal fouling properties of a severely hydrotreated Occidental shale oil, a JP-8 fuel derived from the hydrotreated shale oil and a relatively fresh Paraho shale oil have also been determined.

#### Experimental Development

The UOP Monirex Fouling Monitor, previously described in considerable detail in the Phase II report, was used to evaluate the relative thermal fouling properties of shale and petroleum oils. This unit measured the temperature of the fluid ( $T_F$ ), the wire ( $T_W$ ) and the heat input ( $Q$ ) to the wire. Since the wire area was known, it was possible to calculate the heat transfer coefficient ( $h$ ) as well as the fouling factor ( $R_F$ ) and the fouling rate ( $dR_F/dt$ ).

Chemical analyses of materials used in this study including the Occidental desalted and high-pressure (second-stage) hydrotreated shale oil, the JP-8 derived from the hydrotreated oil, and the Arabian Light Berri petroleum desalted crude oil are shown in Table 35. Significant differences between the desalted petroleum and shale oils are the higher Bromine number, gravity and nitrogen content of the shale oil and the higher sulfur content in the petroleum oil. The hydrotreated Occidental shale oil, however, has a significantly lower Conradson carbon, Bromine number, iron, sulfur, nitrogen content and gravity than the original desalted oil.

Unfortunately, the state-of-the-art in predicting fouling has not advanced sufficiently to predict potential thermal fouling characteristics based on chemical analysis. However, as will be shown later, it is apparent that reduction in the sulfur and unsaturated compounds content as well as metals such as iron and nickel did result in lower fouling in the hydro-treated shale oil.

The thermal fouling characteristics of the Arabian Light Berri desalted petroleum crude and Occidental shale oil previously evaluated in June, 1980, were again reevaluated in March, 1981. Data from both tests are given in Tables 36 and 37, and in Figures 15 and 16.

The estimated age of the Occidental desalted shale oil by June, 1980 was 13 months, and 22 months by March, 1981. The Arabian Light Berri petroleum desalted crude was in storage about 8 months by June, 1980, and 17 months by March, 1981. Both oils were sparged with nitrogen when received and stored at 4.4°C (40°F) until ready for test. Prior to testing they were moved into a 40°C (105°F) room and stored there during the entire test period.

#### Discussion of Results

A regression analysis was made of the data and the fouling rate calculated for the 200° to 400°C (392° to 752°F) temperature range. As shown in Table 38, the aging of the Occidental desalted shale oil and the Arabian Light Berri petroleum crude oil significantly reduced fouling on the iron wire.

To illustrate potential effects of aging, the 250°C (482°F) fouling data, were plotted (Figure 17) assuming the fouling rate decreased linearly or exponentially. These data suggest that the  $dR_F/dt$  of the Occidental desalted shale oil had probably decreased by a factor of 5 to 10 times after aging at 4.4°C (40°F) for 22 months, and the Arabian Light Berri desalted petroleum crude decreased by a factor of 1.5 to 2 times after aging for 8 months. It is apparent, therefore, that more meaningful fouling data could be obtained with fresh samples.

Because it is anticipated that the shale oils will be blended with petroleum stocks for processing, the thermal fouling properties of blends of the Arabian Light Berri desalted crude containing 10 and 30% (by weight) of the Occidental desalted shale oil were determined. The data from these test are given in Tables 39 and 40 and presented graphically in Figures 18 and 19. When compared with the 100% petroleum and 100% shale oil results, it is apparent from examining Figure 20 that there were no significant differences in the thermal fouling characteristics of the blends. Blending did not result in the formation of any new fouling components, and the data actually show a minor decrease in fouling tendencies. These two oils, however, are quite old and the effect of blending should be repeated with fresh samples.

The thermal fouling properties of a high-pressure hydrotreated Occidental shale oil were determined and these data are shown in Table 41 and Figure 21. These data show that the high-pressure hydrotreated shale oil was a low fouling material with an activation energy significantly higher than that of the original desalted oil. Although specific compounds have not been identified, it can be speculated that this reduction in fouling is due to the reduction in concentration of unsaturated sulfur and nitrogen compounds. Fouling rate data calculated from a regression analysis of the data in Figure 21 for the 200° to 400°C (392°-752°F) region are given in Table 38.

The thermal fouling characteristics of a JP-8 derived from the high-pressure hydrotreated Occidental shale oil were determined and these data are summarized in Table 42 and Figure 22. These data show that the JP-8 had fouling properties greater than the hydrotreated shale oil but slightly lower than the original desalted oil. Apparently the catalytic process, converting the hydrotreated oil to the JP-8, results in the production of products which can foul thermally on a heated iron wire. No data were available to identify these products. Fouling rates calculated for the 200° to 400°C (392°-752°F) region are shown in Table 38.

In the Phase II report, the relative thermal fouling properties of two Paraho shale oils were reported. The fouling reactions did not

apparently follow a typical Arrhenius concept, and it was speculated that these deviations were due to the presence of oxygenates. More recent experiments indicate that excessive fouling of the probe was responsible.

The test method requires that a build-up of fouling deposit has only a minor effect on the surface area or diameter of the original wire. It was shown that at temperatures from 250° to 311°C (482°-592°F), a relatively long time of exposure of the iron wire at a constant voltage to Occidental desalted shale oil resulted in only minor changes in the fouling rate. The data from a similar set of experiments at 145° and 184°C (293° and 363°F) with the Paraho shale oil are summarized in Table 43 and Figure 23. It was obvious from the dramatic change in observed fouling rate that a build-up of deposit had occurred. Therefore, it was not possible with the high fouling materials to use the same experimental technique in which the probe temperature is increased during a run. A new probe must be used at each new temperature.

A new series of experiments were made with the Paraho shale oil employing a new probe for each new temperature (3 hours per test). Based on the data in Table 44 and shown in Figure 24, the new data are more reasonable and consistent than those obtained previously with the incremental increase in temperature technique. A regression analysis of the data was made, and the fouling rate in the 200° to 400°C (392°-752°F) range given in Table 38, confirms that the Paraho shale oil has a high fouling tendency.

During Phase II, Paraho shale oil was treated with a proprietary antifoulant resulting in a significant decrease in fouling rate. A second Paraho shale oil was also treated with the same proprietary antifoulant (40 ppm) and these fouling data, are given in Table 45 and Figure 24, also show a significantly reduced fouling rate.

#### Conclusions

The Monirex Fouling Monitor was used to determine the relative thermal fouling properties of aged Arabian Light Berri desalted petroleum,

Occidental desalted shale oil and blends of these oils. In addition, the fouling properties of a hydrotreated Occidental shale oil, a JP-8 derived from this oil and a relatively new Paraho shale oil were also determined. These data, summarized in Table 38 and Figures 25 and 26, show that desalting and hydrotreating decrease the fouling tendency of shale oils, shale oils may have different fouling tendencies, and the aged Occidental shale oil had a fouling tendency similar to an Arabian Light Berri crude.

It was found that aging at 4.4°C (40°F), with relatively short periods at (40°C) 105°F, resulted in significant decreases in fouling rates. Since data are available for only two aging periods, it is difficult to project fouling rates to zero age. Although data are not available to show the fouling properties of a fresh sample, it can be speculated that an exponential decrease in fouling rate with aging indicates a rate 5 to 10 times higher for the fresh Occidental desalted shale oil than that found after 13 months aging, and up to 2 times greater for the Arabian Light Berri desalted petroleum oil when compared to those found after eight months. It is apparent, however, that the most meaningful data must be obtained with fresh samples.

Blending of the desalted Arabian Light Berri petroleum crude oil and the desalted Occidental shale oil at 70:30 or 90:10 ratios, by weight, had no significant effect on the fouling rates of either oil. These data indicate that blending did not result in the formation of any significant quantities of pro- or antifoulant materials. However, the activation energy of the fouling reactions of the blends were slightly higher than those of the original materials suggesting the possibility of a different fouling reaction mechanism. The original samples were quite old, with relatively low fouling rates, and it is apparent that these studies should be repeated with fresh oils.

The high-pressure hydrotreated Occidental shale oil had a very low fouling rate. Although the analytical data show substantial removal of unsaturated sulfur, iron and nitrogen compounds by hydrotreating, specific compounds responsible for fouling have not been identified. The

activation energy of the hydrotreated oil fouling reaction is very high suggesting a different mechanism for the fouling reactions on the iron wire.

A JP-8 derived from the high-pressure hydrotreated Occidental desalted shale oil has a relatively low thermal fouling rate. This rate was slightly higher than that of the hydrotreated shale oil but lower than that of the original shale oil. Hydrocracking, the process used to make the JP-8, must apparently produce new precursors of fouling reactions as indicated by the reduction of the activation energy from 18 kcal to 6.5 kcal for the JP-8.

It was also shown that only low fouling materials such as the petroleum and the aged Occidental shale oil used can be evaluated with a single probe for all of the temperatures selected for fouling studies. A high fouling material, such as the relatively fresh Paraho shale oil, must be evaluated with a new probe at each new test temperature. Significant foulant build-up on the iron wire probe can change the wire surface area. Under these new conditions, it was shown that the Paraho shale oil fouling rate was approximately an order of magnitude higher than for the petroleum or Occidental shale oil.

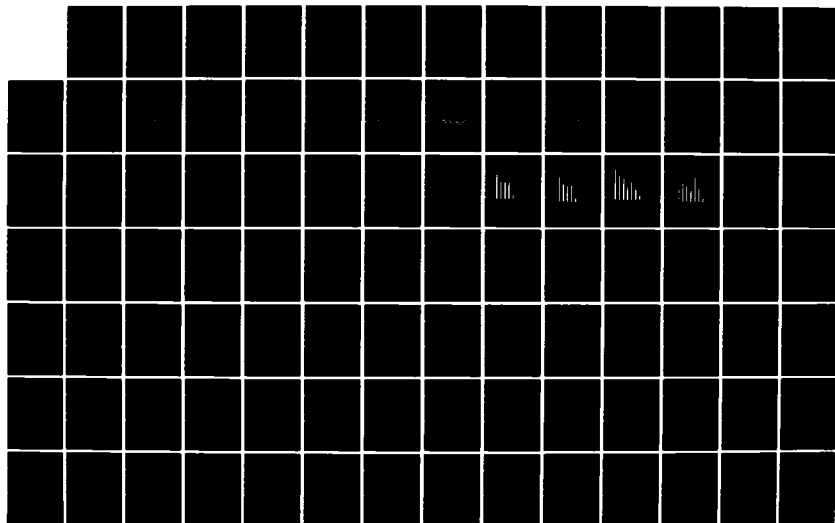
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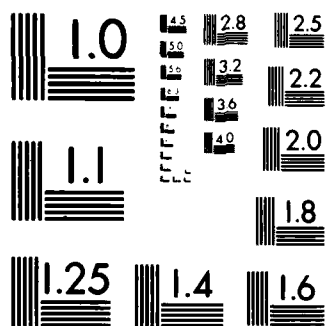
USAF SHALE OIL TO FUELS VOLUME 2 PHASES 3 AND 4(U) UOP 2/4  
INC DES PLAINES IL PROCESS DIV J G SIKONIA ET AL.  
JUL 82 AFMAL-TR-81-2116-VOL-2 F33615-78-C-2879

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TABLE 35. ANALYSIS OF OCCIDENTAL DESALTED AND HYDROTREATED SHALE OIL,  
JP-8 FROM HYDROTREATED OIL, PARAHO SHALE OIL  
AND ARABIAN LIGHT BERRI DESALTED PETROLEUM OIL

	Light Berri Oil	Occidental Shale		JP-8	Paraho Shale Oil
		Deashed Oil	HP Hydrotreated Oil		
API Gr. at 60°F	35.4	22.9	32.3	45.1	19.8
Sp. Gr. at 60°F	0.8478	0.9165	0.8639	0.8012	0.9352
Bubble Pt. at 500 psig, °F	720	1056			
Distillation (D-1160), °F					
IBP	127	376	430	295	408
5%	225	467	469	314	471
10%	274	510	495	330	525
30%	420	621	581	359	670
50%	589	712	663	438	789
70%	782	820	760	474	889
87%	1083	953			1005
90%			958	512	
% Over	90	87	97	99	90
% Bottoms	10	13	3	--	10
Con. Carbon, wt-%	-	1.36	0.06	-	2.71
Nitrogen, wt-%	840 ppm	1.5	680 ppm	1.1 ppm	2.2
Bromine Number	1.2	23.6	1.3	-	34.7
Ash, wt-%	0.001	0.014	-	-	0.007
C7 Insol., wt-%	0.55	0.34	0.06	-	0.47
Emission, ppm					
Fe	0.55	42	1.3	-	38
Mn	-	<0.2	-	-	-
Cr	-	0.21	-	-	-
Ni	2.4	6.7	0.25	-	2.2
Mo	-	1.6	<0.1	-	0.12
Cu	<0.1	<0.1	<0.1	-	0.18
H <sub>2</sub> O, wt-%	323 ppm	0.05	-	-	<0.01
Arsenic, ppm	-	27.5	-	-	19
Sulfur, wt-%	1.34	0.64	0.012	282 ppm	0.70
Total O, wt-%	851 ppm	0.65	-	-	1.58
Carbon, wt-%	85.74	84.99	85.8	84.3	-
Hydrogen, wt-%	12.96	12.27	13.6	13.9	-
Diene Value	-	31.6	-	-	-

TABLE 36. EFFECT OF WIRE TEMPERATURE ON h AND  $dR_F/dt$  VALUES  
OF AGED OCCIDENTAL DESALTED SHALE OIL

Period	Temperature, °C		Wire Temp.	h		dR <sub>F</sub> /dt x 10 <sup>-5</sup>
	Fluid	Wire	1/K x 10 <sup>-4</sup>	Original	Final	
Run No. 35						
7	92.9	175.8	22.3	223.4	222.1	1.40
8	93.4	187.6	21.7	223.5	223.9	nil
9	93.4	211.2	20.7	227.9	225.0	1.45
10	93.4	235.6	19.7	226.7	222.9	2.52
11	93.4	264.2	18.6	223.1	220.8	2.24
12	93.4	294.6	17.6	218.6	213.1	4.43
13	93.4	327.9	16.6	212.2	204.1	6.08
14	93.4	365.9	15.7	201.5	194.5	6.70
15	93.4	406.8	14.7	191.2	178.8	12.9
16	93.4	458.6	13.7	174.8	155.6	26.7
17	93.9	526.4	12.5	153.1	137.4	30.5
Run No. 37						
7	93.2	185.0	21.8	205.7	204.6	0
8	93.2	197.3	21.2	206.2	204.7	0.36
9	93.2	224.5	20.1	208.5	207.0	0.71
10	93.4	250.2	19.1	208.4	206.2	1.05
11	93.4	280.7	18.0	206.8	204.2	2.10
12	93.4	313.6	17.0	203.2	198.4	4.25
13	93.5	350.1	16.0	197.1	189.8	7.36
14	93.5	392.3	15.0	186.6	177.6	10.2
15	93.5	440.4	14.0	174.6	164.4	12.7
16	93.5	496.0	13.0	160.6	142.3	32.8
Run No. 38						
7	92.0	182.4	21.9	208.6	208.6	0
8	92.0	194.4	21.3	210.3	210.3	0
9	92.0	220.2	20.2	214.3	212.6	0
10	92.0	246.0	19.2	213.6	212.3	0.74
11	92.0	275.9	18.2	212.0	210.7	1.70
12	92.0	307.8	17.2	209.4	205.7	2.67
13	92.5	341.9	16.2	204.7	199.8	4.50
14	92.5	380.1	15.3	197.0	190.9	6.13
15	92.5	421.1	14.4	188.8	181.9	6.89
16	92.7	466.4	13.5	179.2	172.2	8.19

TABLE 37. EFFECT OF WIRE TEMPERATURE ON  $h$  AND  $dR_F/dt$  VALUES  
OF AGED ARABIAN LIGHT BERRI PETROLEUM CRUDE OIL

<u>Period</u>	<u>Temperature, °C</u>		<u>Wire Temp.</u>	<u>h</u>		<u>dR<sub>F</sub>/dt</u>
	<u>Fluid</u>	<u>Wire</u>	<u>1/K x 10<sup>-4</sup></u>	<u>Original</u>	<u>Final</u>	<u>x 10<sup>-5</sup></u>
<u>Run No. 33</u>						
7	90.7	179.5	22.1	206.2	207.3	n11
8	91.1	190.6	21.6	209.8	210.7	n11
9	91.6	215.7	20.5	214.7	214.7	n11
10	91.6	240.1	19.5	214.9	214.7	n11
11	92.0	268.2	18.5	214.5	214.5	n11
12	92.0	298.0	17.5	212.0	206.6	4.16
13	92.1	333.7	16.5	203.4	194.8	7.10
14	91.6	375.7	15.4	190.4	182.2	6.96
15	91.8	421.5	14.4	177.1	168.1	11.26
16	91.8	473.0	13.4	163.5	155.8	11.26
<u>Run No. 36</u>						
7	90.8	182.1	22.0	196.4	197.5	n11
8	90.8	193.2	21.4	201.6	199.9	n11
9	90.9	218.3	22.2	204.6	205.0	n11
10	91.1	242.8	19.4	205.8	205.8	n11
11	91.2	271.4	18.4	207.1	207.1	n11
12	91.4	300.0	17.4	206.9	205.5	1.18
13	91.7	330.9	16.6	204.8	200.5	3.81
14	91.7	365.6	15.7	198.9	193.8	5.00
15	91.8	403.6	14.8	191.3	181.7	8.24
16	91.8	449.0	13.8	178.9	171.8	9.05

TABLE 38. FOULING CHARACTERISTICS OF SHALE AND PETROLEUM PRODUCTS

Temperature, °C    °F		Fouling Rate $dR_F/dt \times 10^{-5}$								
		Occidental Shale		Light Berri		ALB-90	ALB-70	HPOS	Paraho	JP-8 from
		13 Mo	22 Mo	8 Mo	17 Mo	OS-10	OS-30		3 Mo	HPHOS
200	392	3.49	1.07*	1.32	1.55*	0.59*	0.41*	0.009*	28	0.5
225	437	4.75	1.51	2.27	2.04*	0.90*	0.68*	0.02*	35	0.7
250	482	5.94	2.08	3.26	2.62*	1.32*	1.08*	0.06*	43	1.1
275	527	7.27	2.77	4.80	3.28*	1.87*	1.65*	0.13*	52	1.58
300	572	8.75	3.61	6.67	4.03	2.58	2.42	0.27*	62	2.23
325	617	10.37	4.61	9.01	4.87	3.46	3.45	0.51*	72	3.01
350	662	12.12	5.76	11.86	5.79	4.53	4.76	0.94*	83	4.07
375	707	14.00	7.07	15.30	6.80	5.81	6.43	1.65	95	5.27
400	752	15.97	8.55	19.34	7.87	7.30	8.46	2.77	107	6.53
Activation Energy cal/mol		-4626	-6613	-8176	-5142	-7797	-9605	-18011	-4214	-8550

\* = Calculated Values - Actual Values  $dR_F/dt < 0.5 \times 10^{-5}$

ALB = Arabian Light Berri Petroleum Crude

OS = Occidental Shale Oil

HPHOS = High Pressure Hydrotreated Occidental Shale Oil

3 Mo. = Estimated Age of 3 Months

TABLE 39. EFFECT OF TEMPERATURE ON  $h$  AND  $dR_F/dt$  VALUES  
OF A 90:10 (BY WEIGHT) BLEND OF  
ARABIAN LIGHT BERRI DESALTED PETROLEUM CRUDE AND OCCIDENTAL SHALE OILS

Period	Temperature, °C		Wire Temp. 1/K x 10 <sup>-4</sup>	h		dR <sub>F</sub> /dt x 10 <sup>-5</sup>
	Fluid	Wire		Original	Final	
Run No. 41						
7	91.3	178.7	22.1	209.2	208.7	nil
8	91.3	190.6	21.6	211.7	211.7	nil
9	91.6	215.6	20.5	214.5	214.2	nil
10	91.6	240.1	19.5	216.2	213.8	0.88
11	91.8	268.2	18.5	214.9	212.9	0.68
12	91.8	298.4	17.5	212.3	209.1	2.27
13	91.8	330.8	16.6	206.6	202.8	3.85
14	91.8	366.7	15.6	199.8	193.5	6.06
15	92.0	405.5	14.7	191.6	183.7	8.29
16	92.0	449.5	13.8	181.2	173.1	9.16
Run No. 42						
7	90.7	178.0	22.2	213.6	213.6	nil
8	90.7	189.8	21.6	215.2	214.4	nil
9	90.9	215.0	20.5	217.3	216.6	nil
10	90.9	239.9	19.5	216.5	215.9	1.23
11	90.9	269.2	18.4	214.3	214.2	nil
12	91.1	299.1	17.5	212.6	211.3	1.78
13	91.3	331.8	16.5	207.6	202.4	3.52
14	91.6	367.9	15.6	200.7	188.1	10.71
15	91.6	415.5	14.5	184.7	174.1	10.51
16	91.6	464.9	13.6	171.1	166.0	8.06

TABLE 40. EFFECT OF TEMPERATURE ON h AND  $dR_F/dt$  VALUES  
OF A 70:30 (BY WEIGHT) BLEND OF  
ARABIAN LIGHT BERRI DESALTED PETROLEUM AND OCCIDENTAL DESALTED SHALE OILS

Period	Temperature, °C		Wire Temp. 1/K x 10 <sup>-4</sup>	h		dR <sub>F</sub> /dt x 10 <sup>-5</sup>
	Fluid	Wire		Original	Final	
Run No. 39						
7	91.6	176.4	22.2	219.8	219.8	nil
8	91.8	187.9	21.7	220.8	220.8	nil
9	91.8	213.0	20.6	222.4	222.3	nil
10	91.8	237.1	19.6	222.2	222.0	nil
11	91.8	264.8	18.6	221.4	220.9	0.85
12	91.8	293.5	17.6	219.9	219.6	0.70
13	91.8	324.3	16.7	216.8	213.3	3.22
14	92.1	358.7	15.8	209.5	203.8	4.71
15	92.3	399.4	14.9	199.5	182.5	15.17
16	92.3	450.2	13.8	181.8	172.1	10.16
Run No. 40						
7	91.3	178.4	22.2	211.9	213.8	nil
8	91.3	189.5	21.6	213.9	215.0	nil
9	91.8	214.1	20.5	218.7	218.2	nil
10	91.6	238.4	19.6	218.5	218.5	nil
11	91.6	266.0	18.6	218.1	218.1	nil
12	91.7	294.4	17.6	217.6	215.7	1.56
13	91.7	326.1	16.7	213.1	208.1	3.85
14	91.7	364.2	15.7	202.9	194.7	7.89
15	91.8	406.8	14.7	190.6	178.6	12.16
16	91.8	456.1	13.7	176.0	168.5	9.76

TABLE 41. EFFECT OF PROBE TEMPERATURE ON  $h$  AND  $dR_F/dt$   
OF HIGH PRESSURE HYDROTREATED OCCIDENTAL SHALE OIL

Period	Temperature, °C		Wire Temp. 1/K x 10 <sup>-4</sup>	h		dR <sub>F</sub> /dt x 10 <sup>-5</sup>
	Fluid	Wire		Original	Final	
Run No. 47						
7	91.1	174.0	22.4	226.8	226.8	n11
8	91.6	184.8	21.8	231.0	231.0	n11
9	91.6	209.4	20.7	231.7	231.7	n11
10	91.6	232.9	19.8	231.9	231.9	n11
11	92.0	261.0	18.7	230.0	230.0	n11
12	92.0	288.5	17.8	229.0	229.0	n11
13	92.0	318.1	16.9	226.6	226.6	n11
14	92.5	348.8	16.1	223.8	223.8	n11
15	92.5	380.4	15.3	220.4	218.3	1.94
16	92.5	414.9	14.5	214.7	208.6	4.23
Run No. 49						
7	90.7	183.1	21.9	193.4	193.4	n11
8	90.7	194.3	21.4	197.0	197.0	n11
9	90.7	219.6	20.3	201.0	201.0	n11
10	91.1	243.9	19.3	203.9	203.9	n11
11	90.7	270.4	18.4	206.1	206.1	n11
12	90.7	297.8	17.5	208.1	208.1	n11
13	90.7	328.8	16.6	205.2	205.2	n11
14	91.1	359.4	15.8	204.2	204.2	n11
15	92.0	390.1	15.1	203.9	201.9	1.97
16	92.0	425.1	14.3	199.5	193.9	4.70
17	91.6	466.1	13.5	190.5	181.8	9.07
18	91.6	515.9	12.7	177.3	171.8	8.71

TABLE 42. EFFECT OF WIRE TEMPERATURE ON  $h$  AND  $dR_F/dt$   
OF JP-8 DERIVED FROM  
HIGH-PRESSURE HYDROTREATED OCCIDENTAL SHALE OIL

Period	Temperature, °C		Wire Temp. 1/K x 10 <sup>-4</sup>	h		dR <sub>F</sub> /dt x 10 <sup>-5</sup>
	Fluid	Wire		Original	Final	
Run No. 64						
5	96.1	155.9	23.3	169.1	169.1	nil
6	96.2	178.2	22.2	179.1	180.4	nil
7	96.3	193.0	21.5	183.4	182.0	0.26
8	96.3	205.9	20.9	184.1	186.6	nil
9	96.4	232.7	19.8	188.2	188.4	nil
10	97.0	258.4	18.8	189.7	189.7	nil
11	97.5	287.4	17.8	191.7	190.0	1.62
12	98.2	319.7	16.9	189.8	186.1	3.20
13	98.4	353.9	16.0	155.5	152.1	4.35
14	98.6	389.8	15.1	181.7	177.6	4.15
Run No. 65						
7	100.2	251.2	19.1	211.1	211.1	nil
8	100.5	280.5	18.1	210.2	208.4	1.81
9	100.5	311.7	17.1	207.6	205.0	2.46
10	100.5	344.5	16.2	203.1	198.1	3.29
11	100.5	380.0	15.3	197.3	193.2	3.98
12	100.8	417.3	14.5	191.8	186.9	4.67
13	100.8	456.7	13.7	184.9	174.0	11.74
14	100.8	504.2	12.9	174.2	160.2	16.75

TABLE 43. EFFECT OF TIME AT CONSTANT WIRE VOLTAGE  
ON  $h$  AND  $dR_F/dt$  OF PARAHO SHALE OIL

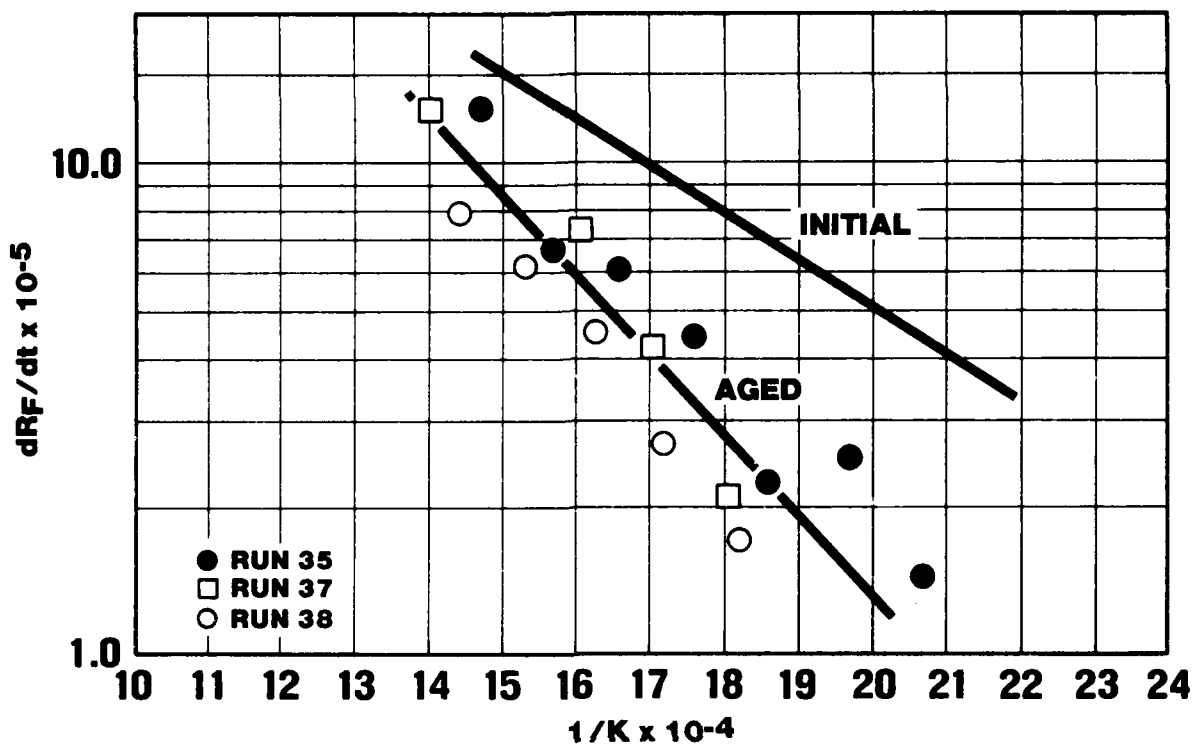
Period, hours	Temperature, °C		Wire Temp. 1/K x 10 <sup>-4</sup>	h		dR <sub>F</sub> /dt x 10 <sup>-5</sup>
	Fluid	Wire		Original	Final	
Run No. 60						
0-3	92.4	183.8	21.9	234.8	189.2	33.6
3-6	92.4	201.1	21.1	188.2	168.5	20.3
6-9	92.4	211.6	20.6	167.1	153.5	18.0
9-12	92.3	219.8	20.3	153.1	141.4	17.7
12-15	92.4	227.8	20.0	140.7	130.8	16.6
15-18	89-95	240.0	19.5	127.5	119.8	19.7
18-21	89-95	245.3	19.3	121.6	116.7	17.0
21-24	92.3	248.6	19.2	116.1	112.1	14.0
0-24	92.4	183.8	21.9	234.8	112.1	19.4
Run No. 61						
0-3	92.6	144.9	23.9	199.0	167.6	26.5
3-6	92.6	153.2	23.5	167.6	154.2	15.1
6-9	92.7	157.2	23.2	154.2	148.2	10.4
9-12	92.6	159.4	23.1	148.2	141.8	8.23
12-15	92.6	161.8	23.0	142.3	139.4	5.58
15-18	92.7	162.9	22.9	139.4	136.1	2.15
18-21	92.8	164.3	22.9	136.1	134.5	2.77
21-24	92.8	165.7	22.8	132.9	131.4	6.48
24-27	92.8	166.9	22.7	131.3	130.2	4.09
27-30	92.8	167.3	22.7	130.2	128.4	2.13
30-33	92.7	168.3	22.7	128.2	127.1	3.22
33-36	92.8	168.7	22.6	127.1	126.5	0.70
36-39	91.6-92.9	168.7	22.6	126.5	125.4	n11
39-42	92.7	169.8	22.6	124.6	124.2	n11
42-45	92.8	170.2	22.6	124.2	124.2	n11
45-48	92.8	170.2	22.6	124.2	122.6	3.65
48-51	92.9	170.6	22.5	122.6	122.8	n11
51-54	92.8	170.9	22.5	122.8	121.7	2.94
54-57	92.7	171.3	22.5	121.7	120.7	1.89
57-60	92.8	171.7	22.5	120.7	120.7	1.64
0-60	92.7	144.9	23.9	199.0	120.7	5.43

TABLE 44. EFFECT OF TEMPERATURE ON h AND  $dR_F/dt$  VALUES  
OF PARAHO SHALE OIL.  
NEW WIRE PROBE AT EACH NEW TEMPERATURE

<u>Period</u>	<u>Temperature, °C</u>		<u>Wire Temp.</u> <u>1/K x 10<sup>-4</sup></u>	<u>h</u>		<u><math>dR_F/dt</math></u> <u>x 10<sup>-5</sup></u>
	<u>Fluid</u>	<u>Wire</u>		<u>Original</u>	<u>Final</u>	
58	92.0	143.0	24.0	203.4	191.5	11.9
61	92.5	145.8	23.9	199.0	167.6	26.5
62	91.1	148.8	23.7	179.8	164.2	17.4
56	92.5	165.2	22.9	206.8	188.0	15.8
60	92.4	183.8	21.9	234.8	189.2	33.6
55	91.8	186.8	21.8	226.9	202.6	16.8
54	91.8	188.7	21.7	220.6	194.5	18.9
53	91.6	190.9	21.5	206.6	170.1	32.8
57	92.2	213.0	20.6	224.8	194.8	25.1
59	91.6	235.8	19.6	223.2	162.5	52.6

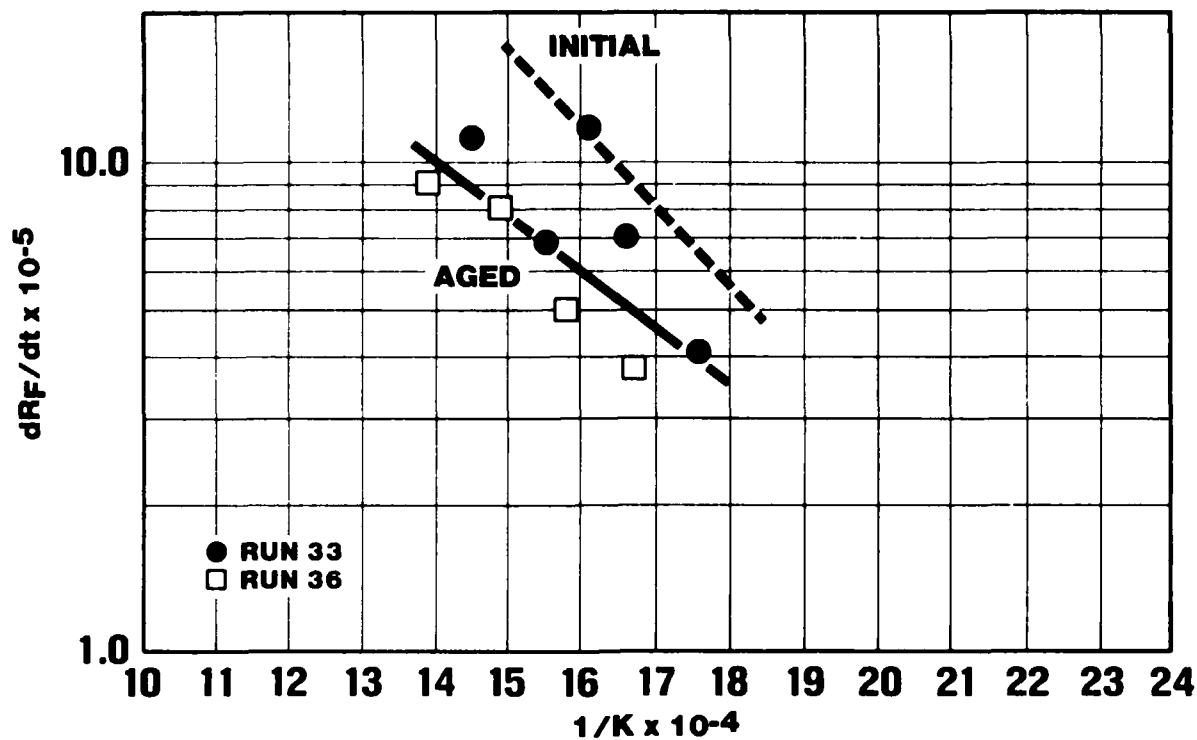
TABLE 45. EFFECT OF PROPRIETARY ANTIFOULANT  
ON FOULING RATE AND h VALUES OF PARAHO SHALE OIL

<u>Period</u>	<u>Temperature, °C</u>		<u>Wire Temp.</u> <u>1/K x 10<sup>-4</sup></u>	<u>h</u>		<u>dR<sub>F</sub>/dt</u> <u>x 10<sup>-5</sup></u>
	<u>Fluid</u>	<u>Wire</u>		<u>Original</u>	<u>Final</u>	
10	92.2	173.0	22.4	235.4	237.1	nil
11	92.6	183.3	21.9	236.5	241.9	nil
12	92.3	206.2	20.9	241.2	245.8	nil
13	92.3	228.2	20.0	244.6	228.8	11.97
14	92.5	263.6	18.6	225.6	203.7	17.5



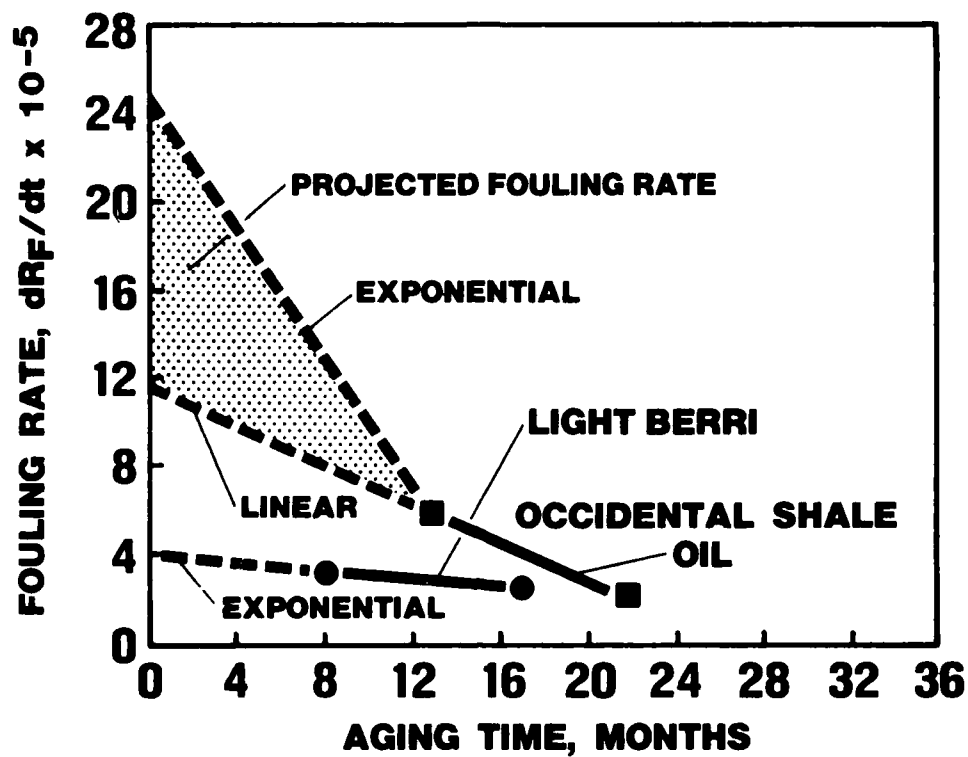
UOP 734-1

**FIGURE 15**  
**EFFECT OF TEMPERATURE AND AGING ON**  
**FOULING RATE OF DESALTED OCCIDENTAL**  
**SHALE OIL**

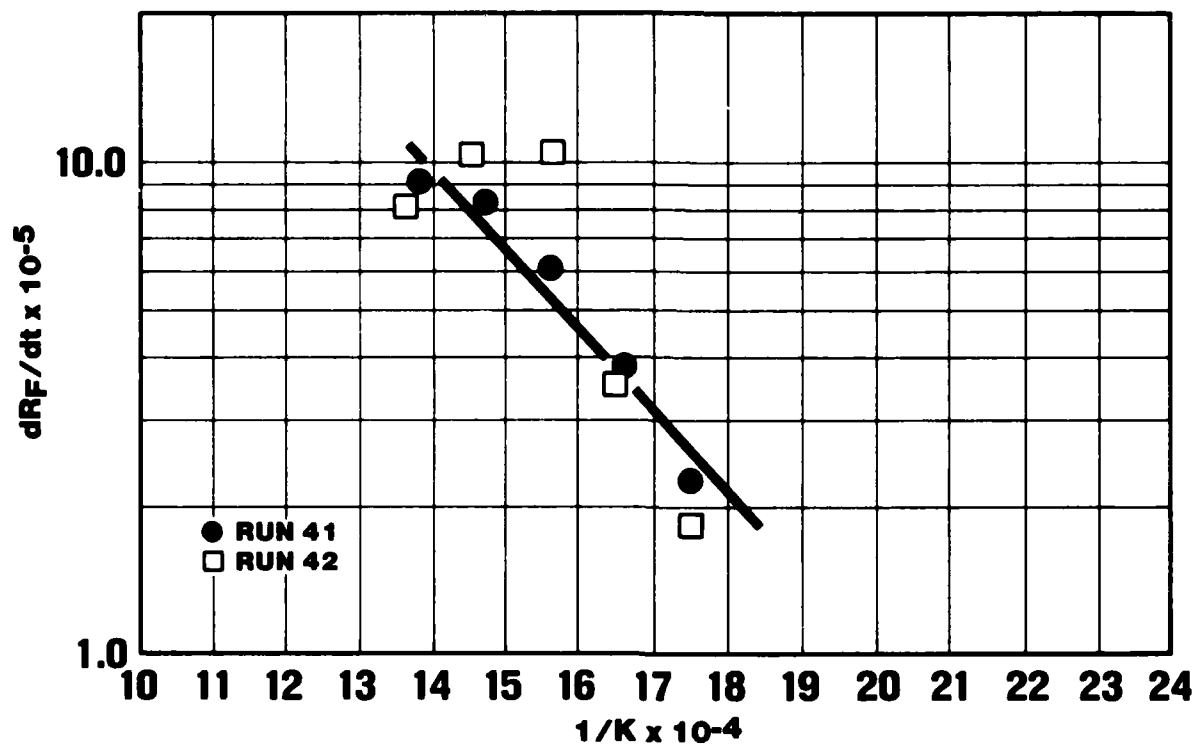


UOP 734-2

**FIGURE 16**  
**EFFECT OF TEMPERATURE AND AGING ON**  
**FOULING RATE OF DESALTED ARABIAN LIGHT**  
**BERRI PETROLEUM OIL**

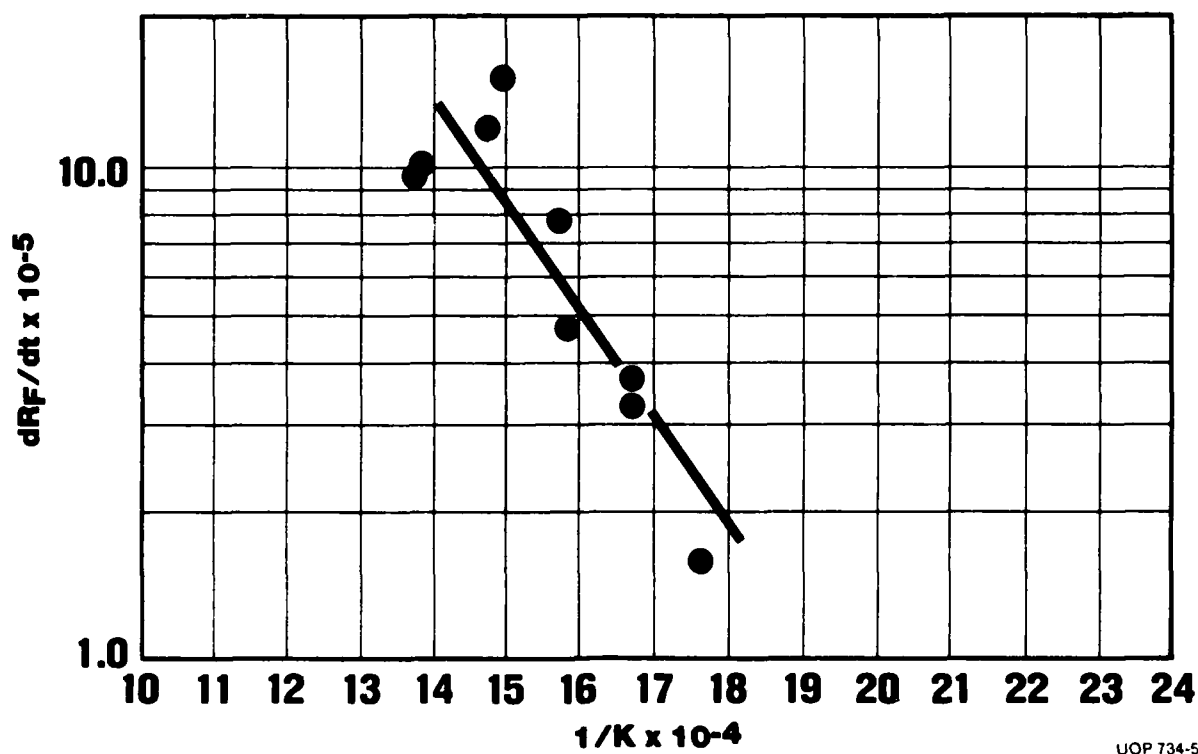


**FIGURE 17**  
**EFFECT OF AGING ON FOULING RATE**

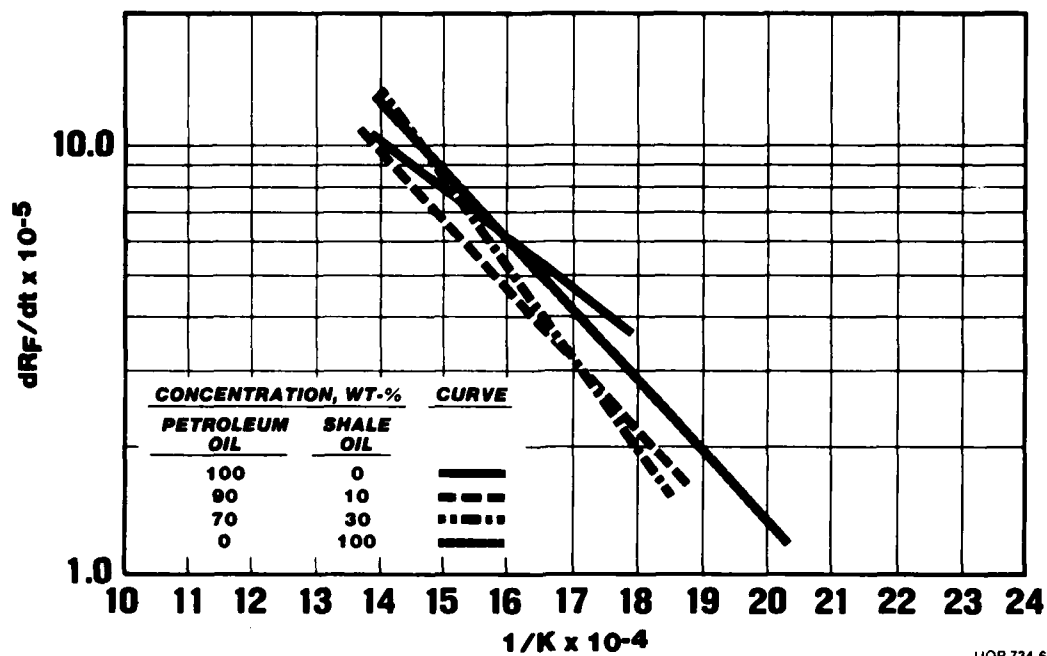


UOP 734-4

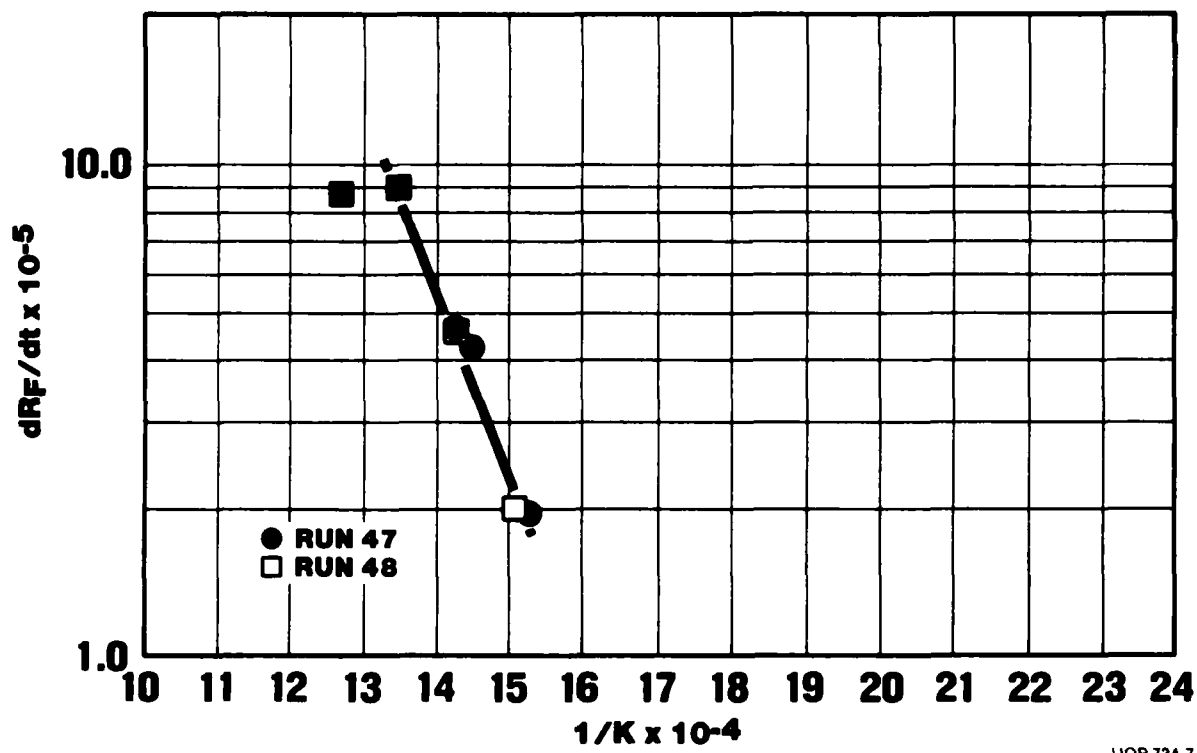
**FIGURE 18**  
**FOULING RATE OF 1:9 BLEND OF DESALTED**  
**OCCIDENTAL SHALE AND ARABIAN LIGHT**  
**BERRI PETROLEUM OILS**



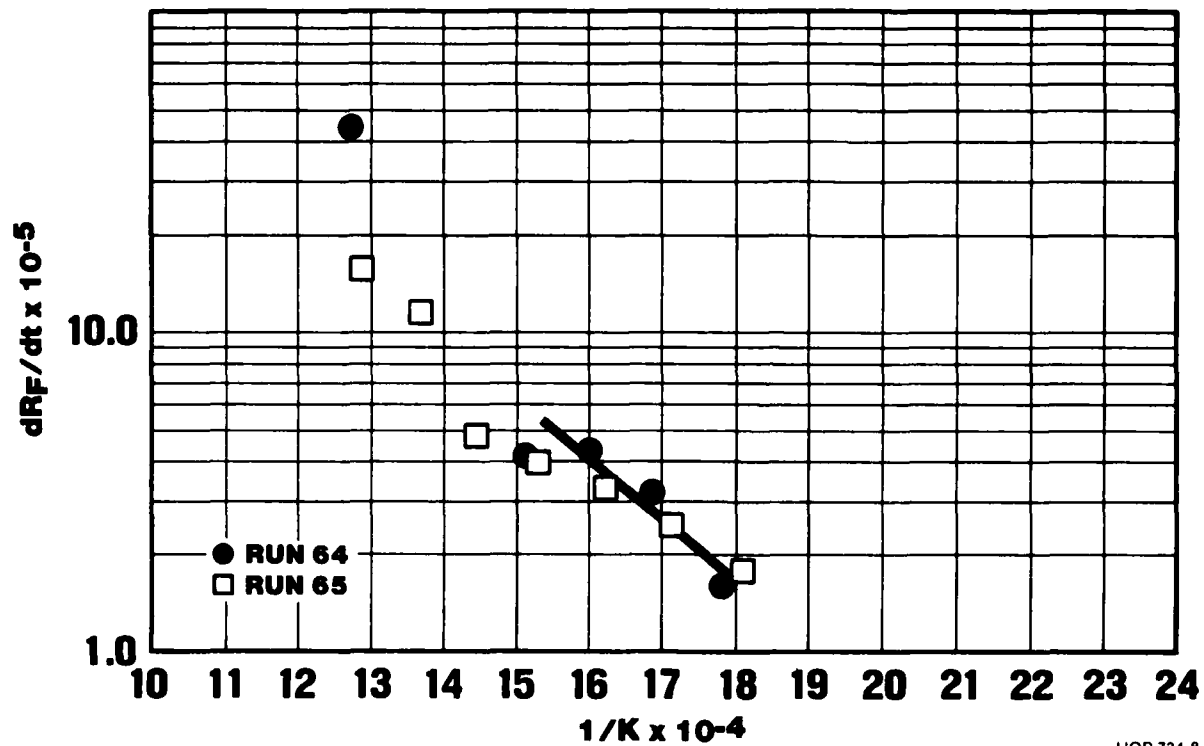
**FIGURE 19**  
**FOULING RATE OF 3:7 BLEND OF DESALTED**  
**OCCIDENTAL SHALE AND ARABIAN LIGHT**  
**BERRI PETROLEUM OILS**



**FIGURE 20**  
**EFFECT OF BLENDING ON FOULING RATE**

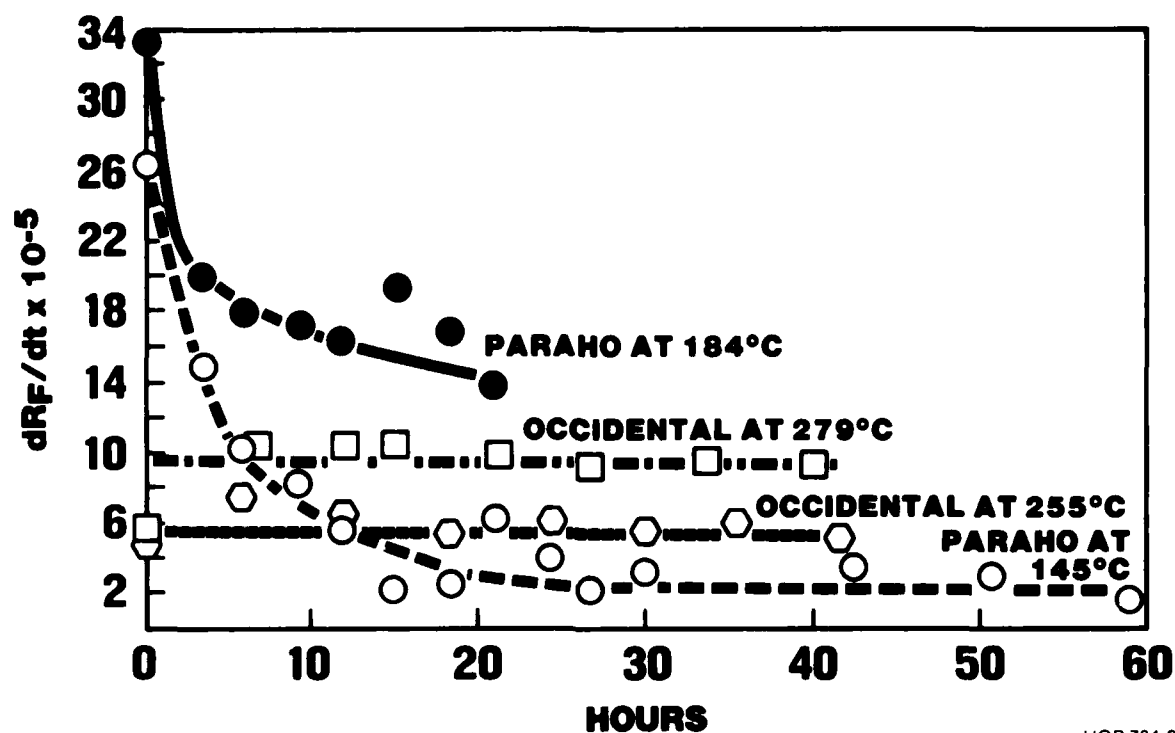


**FIGURE 21**  
**FOULING RATE OF HYDROTREATED**  
**OCCIDENTAL SHALE OIL**



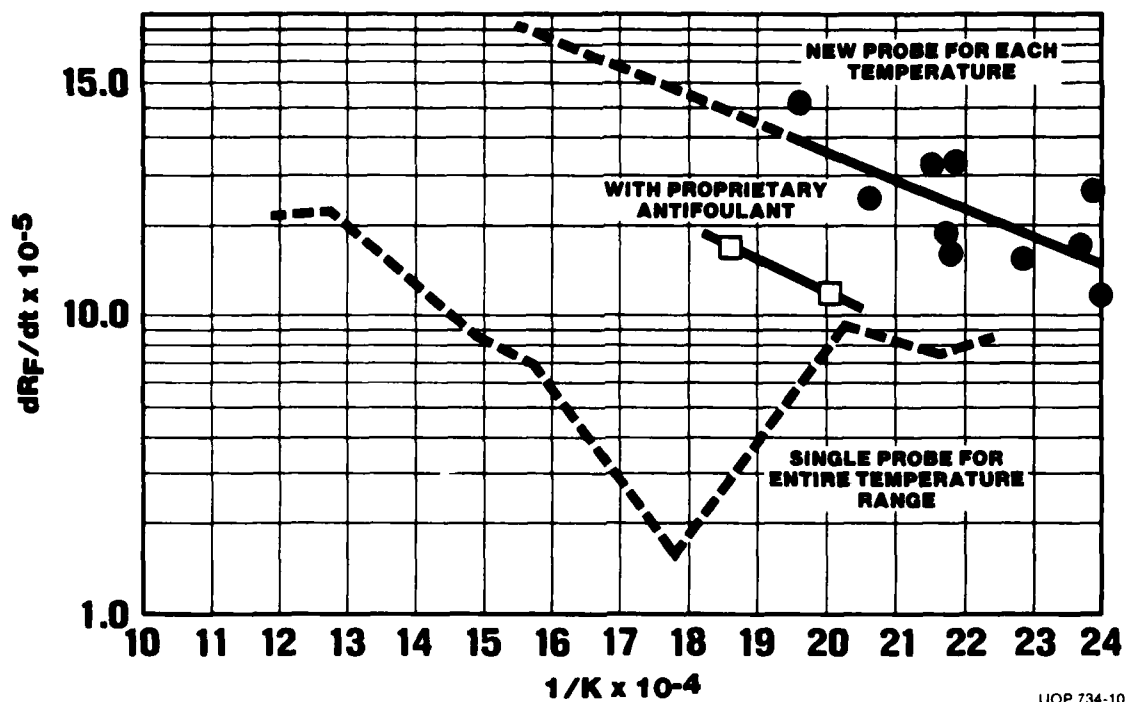
UOP 734-8

**FIGURE 22**  
**FOULING RATE OF JP-8 FUEL**  
**FROM HYDROTREATED SHALE OIL**

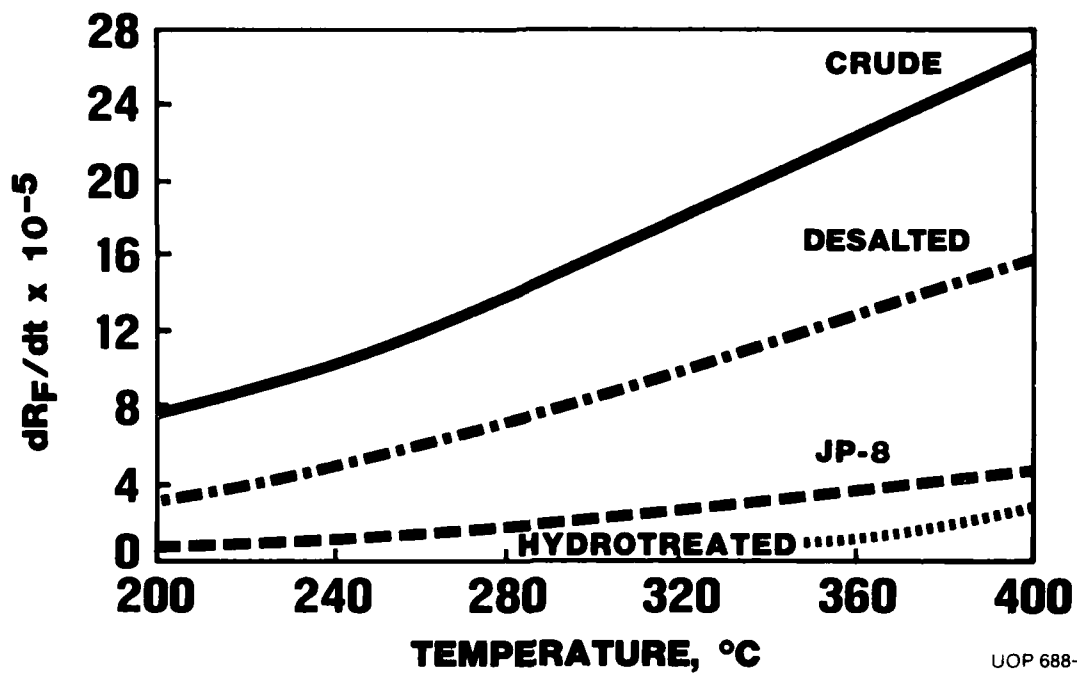


UOP 734-9

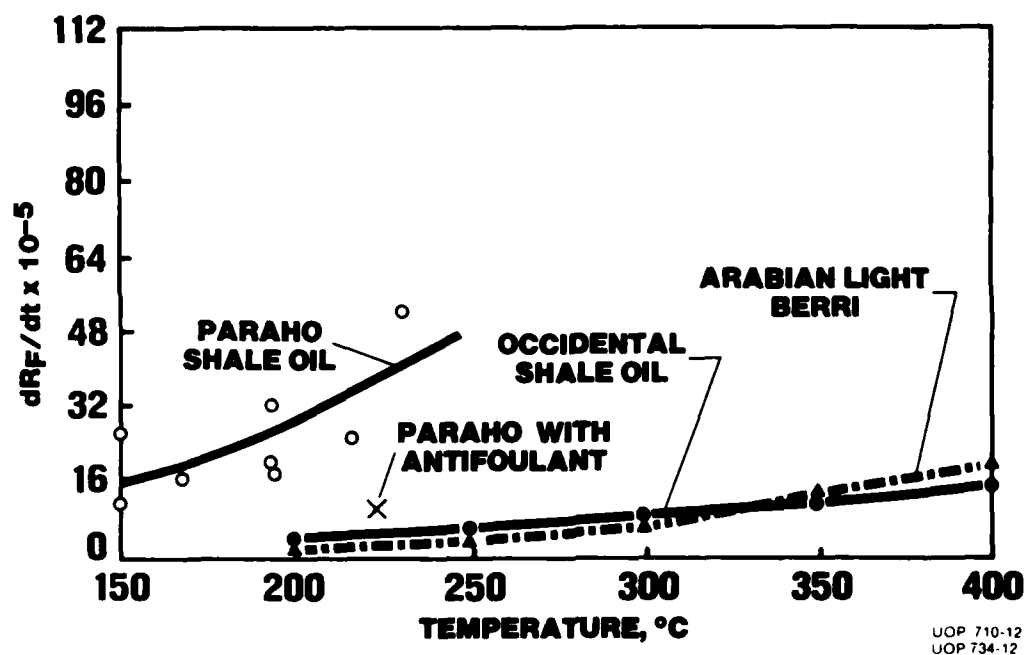
**FIGURE 23**  
**FOULING RATES OF DESALTED**  
**OCCIDENTAL AND PARAHO**  
**SHALE OILS**



**FIGURE 24**  
**FOULING RATE OF PARAHO SHALE OIL**



**FIGURE 25**  
**EFFECT OF TEMPERATURE ON**  
**THE FOULING RATE OF OCCIDENTAL**  
**SHALE OIL DERIVED FEEDS**



**FIGURE 26**  
**EFFECT OF TEMPERATURE ON FOULING**  
**RATE OF SHALE AND PETROLEUM OILS**

## SECTION VII

### SHALE OIL/PETROLEUM OIL STABILITY/COMPATIBILITY STUDY

#### Introduction

##### Background

Oil shale represents an enormous potential reserve of energy for the United States. Conversion of oil shale to liquid hydrocarbons suitable as substitutes for transportation and heating fuels could augment the United States' reserves. Various pyrolysis processes are presently under development to produce liquid hydrocarbons from oil shale. They include surface processes and "in-situ" processes. Several processes have progressed beyond the small bench scale of the laboratory to the demonstration stage, and now have the capability of producing relatively large quantities of hydrocarbon liquids. Characterization of the liquid generated from these processes is an important consideration in direct utilization or upgrading processes. The immediate and best utilization of hydrocarbon liquids produced from demonstration plants and commercial prototypes may be blending them with petroleum crude oils or fractions thereof and processing the blends in existing refineries.

##### Objectives

The objectives of this study were to determine the stability of primary shale oils and treated products and the compatibility/stability of primary shale oils and treated products with petroleum crude oil. The stability of shale oils and treated products in storage and use is of concern to refiners and users. Whereas many studies have been made on the stability of petroleum liquids, stability of shale oils and treated products have been limited by unavailability of shale oils. Their resistances to chemical change and physical disintegration in storage is not well known. The compatibility of shale oils and treated products with petroleum crude oil is also of concern. The compatibility of shale oils and treated products with petroleum crude oil is an important consideration in

their blending, particularly with respect to co-processing shale oil/petroleum crude oil in existing refineries. The resulting blends should form a homogeneous mixture that neither separates nor is altered by chemical interaction. The physical and chemical properties of the blend should not be adversely affected.

#### Outline of Program

The program involved the stability study of primary shale oil and treated products derived therefrom and the compatibility/stability of primary shale oils and treated products derived therefrom with petroleum crude oil.

The primary shale oils selected were a raw Paraho shale oil and a raw Occidental shale oil. The crude oil selected was a heavy Arabian crude. Treated shale oils were derived from single-stage and two-stage hydrotreatment of the primary shale oils. Compatibility/stability studies of the shale oil/crude oil blend were conducted on blends consisting of 30 volume percent shale oil. The primary shale oils, treated products and petroleum crude oil were deoxygenated and inspected before the blending and subsequent stability testing.

#### Compatibility and Stability Studies

#### Sources and Properties of Primary Samples

Primary Shale Oils -- Paraho shale oil produced by direct fired retort and Occidental shale oil produced by in-situ retorting were selected for study. The Paraho shale oil assigned for work under Phase II of the contract was received in March, 1979. It was from the 100,000 barrels of crude Paraho shale oil produced by Paraho Development Corporation over the three-year period from 1976 to 1978. The raw Paraho shale oil was desalted and dewatered. Inspections are given in Table 46. The Occidental shale oil, also processed under the aforementioned contract, was received in April, 1979. It was from the underground Room 6 retort using Occidental Petroleum Company's Modified In-Situ retorting process.

The raw Occidental shale oil was desalted and dewatered. Inspections are given in Table 46.

Crude Oil -- The foreign crude selected to represent typical Gulf Coast processing status was a heavy Arabian crude. Inspections are given in Table 46.

#### Treatment and Properties of Hydrotreated Shale Oils

Shale Oils -- Shale oils have unique characteristics relative to conventional crude petroleum oil. Unusually high arsenic and iron levels, high pour point and viscosity, a high unsaturates concentration, and a significant solids (ash) content make conventional front-end refining techniques unusable without proper pretreatment. To prepare the shale oil for the primary conversion step -- hydrocracking to jet and other fuels -- two stages of hydrotreatment were selected. The stability of the hydrotreated products and the stability/compatibility of petroleum crude oils blends were studied.

First-Stage Hydrotreatment -- The desalted Paraho shale oil and the desalted Occidental shale oil were processed in a first-stage hydrotreater to provide for removal of certain contaminants and stabilization of the raw shale oil, to allow high severity hydrotreatment and subsequent conversion operations. Inspections are given in Table 46.

Second-Stage Hydrotreatment -- The Paraho and Occidental first-stage hydrotreated products were processed in a second-stage hydrotreater at higher severity to reduce the high levels of impurities such as nitrogen and oxygen to acceptable levels for the primary conversion step -- hydrocracking to jet and other fuels. Inspections are given in Table 46.

#### Experimental Procedures

The preparation and analysis of samples for stability and compatibility testing are described in Appendices A.1 and A.2. The stability tests selected for study were the Three Months 110°F Dark Storage Fuel Oil Stability Test (See Appendix A.3), the E. I. DuPont de Nemours and Co.

300°F Accelerated Fuel Oil Stability Test (1) and the ASTM No. 2274-74 Oxidation Stability of Distillate Fuel Oil Test (2). These tests are applicable to petroleum distillate fuels and were modified to permit stability testing of shale oils, petroleum crude oils and blends thereof (See appendices A.4, A.5 and A.6).

## Results and Discussion

### Stability Studies

Stability was assessed by measuring formation of adherent insolubles and changes in heptane insolubles, toluene insolubles and viscosity. The results obtained are summarized in Tables 47 and 48 and Figures 27 through 30.

Adherent Insoluble Formation -- The samples show relatively good stability with respect to adherent insoluble formation with the possible exception of the 30 volume percent raw Paraho shale oil/heavy Arabian crude blend which had adherent gum values of 2.1 mg/100 mL in the three-months storage test and 10.6 mg/100 mL in the ASTM D 2274-74 test. The other adherent gum values were less than 1 mg/100 mL in the three-month storage test.

C7 Insoluble Stability -- The second-stage hydrotreated Paraho shale oil and the first- and second-stage Occidental shale oils were stable with respect to C7 insolubles.

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(1) Petroleum Laboratory Method No. F21-61, "300°F Accelerated Fuel Oil Stability Test", E.I. Dupont de Nemours and Company, Inc., Wilmington, Delaware, December, 1962.

(2) Annual Book of Standards, Part 24, P. 296, 1977; American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.

The C<sub>7</sub> insolubles of the heavy Arabian crude, the raw and first-stage hydrotreated Paraho shale oil and raw Occidental shale oil increased after stability testing, indicating some measure of instability with respect to C<sub>7</sub> insolubles. The heavy Arabian crude had the highest increase indicating it was the most unstable. Next were the raw Paraho and raw Occidental shale oils which had similar increases. The first-stage hydrotreated Paraho had the lowest increase. Stability with respect to C<sub>7</sub> insolubles improved with the degree of hydrotreatment.

Blending of the raw shale oil with heavy Arabian crude decreases stability with respect to C<sub>7</sub> insolubles as evidenced by the magnitude of the increase in the C<sub>7</sub> insolubles after the three-month storage and the ASTM D 2274-74 test. Blending of the first- and second-stage hydrotreated shale oil with the heavy Arabian crude improves stability with respect to C<sub>7</sub> insolubles as evidenced by the decrease in the magnitude of the increase. Stability of the blends improves with the degree of hydrotreatment.

Viscosity Stability -- The second-stage hydrotreated Paraho shale oil and Occidental shale oil were stable with respect to viscosity. The viscosity of the heavy Arabian crude, raw and first-stage hydrotreated Paraho shale oil, and raw and first-stage hydrotreated Occidental shale oil increased after stability testing, indicating some measure of instability. The heavy Arabian crude had the highest increase indicating it was the most unstable. Next were the raw Paraho and Occidental shale oils which had similar increases. The lowest increases were obtained by the first-stage hydrotreated Paraho and first-stage hydrotreated Occidental shale oil which had similar increases. Stability with respect to viscosity improves with the degree of hydrotreatment. Blending of the heavy Arabian crude oil with the shale oils improves stability with respect to viscosity. Stability of the blends improves with the degree of hydrotreatment.

Toluene Insoluble Stability -- All samples show good stability with respect to toluene insolubles.

## Compatibility Studies

The compatibility of the blends was determined by comparing the experimental values of viscosity, C<sub>7</sub> insolubles and toluene insolubles of the blend to calculated values. The calculated values of viscosity were determined from viscosity blending charts (3, 4). The calculated values of C<sub>7</sub> insolubles and toluene insolubles were determined from the amount of insolubles present in the original samples. The results obtained are summarized in Table 49. Good agreement was obtained between the calculated and experimental values in all the tests indicating that all of the blends of 30 volume percent shale oil/heavy Arabian crude oil are compatible.

## Conclusions

The raw shale oils and hydrotreated products were found to be compatible with the heavy Arabian crude oil.

The raw shale oils, hydrotreated products and heavy Arabian crude showed good stability with respect to toluene insolubles and adherent insolubles.

The second-stage hydrotreated shale oils were found to be stable with respect to C<sub>7</sub> insolubles and viscosity.

The first-stage hydrotreated Occidental shale oil was found to be stable with respect to C<sub>7</sub> insolubles.

The heavy Arabian crude showed some measure of instability with respect to C<sub>7</sub> insolubles and viscosity and was the most unstable of the materials tested.

---

(3) UOP Calculation Charts -- RE Chart I-4.

(4) "Refutas" Viscosity-Temperature Chart Designed by C. I. Kelly, Copyright BAIRO and TATLOCK (London), Ltd.

The raw shale oils showed some measure of instability with respect to C7 insolubles and viscosity but less than the heavy Arabian crude.

The first-stage hydrotreated Paraho shale oil showed some measure of instability with respect to C7 insolubles and viscosity but less than the raw shale oil.

The first-stage hydrotreated Occidental shale oil showed some measure of instability with respect to viscosity but less than the raw shale oil.

Stability with respect to C7 insolubles and viscosity improves with increased hydrotreatment.

Blending of the shale oils with heavy Arabian crude improves stability with respect to viscosity.

Blending of the raw shale oils with heavy Arabian crude decreases stability with respect to C7 insolubles.

Blending of the first- and second-stage hydrotreated shale oil with the heavy Arabian crude improves stability with respect to C7 insolubles. Stability of blends with respect to C7 insolubles and viscosity improves with increased hydrotreatment. Instability reflected in the shale oil/petroleum crude oil blends is accounted for to a great extent by the instability of the petroleum crude oil and should have no adverse effects in co-processing.

The data obtained were derived from shale oils that were stored for two to four years before the compatibility and stability tests were conducted and may not be representative of data derived from fresh commercial samples.

TABLE 46. INSPECTION OF OILS

Name	Heavy Arabian Crude	Paraho Shale Oil		Occidental Shale Oil			
		Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated	Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated
API Gravity at 60°F	26.4	25.2	30.3	33.5	22.5	26.2	32.2
Specific Gravity at 60°F	0.8961	0.9303	0.9111	0.8576	0.9188	0.8973	0.8644
Distillation (D-1160), °F							
IBP	138	372	390	344	399	422	356
5%	189	450	471	438	479	508	450
10%	290	500	517	471	512	538	488
20%	420	585	590	521	572	589	532
30%	518	665	651	574	623	631	570
40%	626	728	710	620	677	672	615
50%	735	784	760	670	729	718	660
60%	851	840	810	721	775	767	710
70%	971	888	861	765	822	812	760
80%	(76) 1039	950	919	821	878	872	810
90%		1025	(95) 1043	(EP) 1009	960	(94) 1010	(EP) 979
% Over	76.0	90.0	95.0	99.0	90.0	94.0	97.0
% Bottoms	24	10.0	5.0	1.0	10.0	6.0	3.0
Carbon, wt-%	80.88	84.6	85.28	85.93	84.59	85.02	85.73
Hydrogen, wt-%	11.22	11.4	12.05	12.40	12.42	12.60	13.01
Oxygen, wt-%	0.93	1.76	0.60	0.26	1.55	0.52	0.28
Sulfur, wt-%	2.97	0.71	0.0746	0.00323	0.68	0.0261	< 0.03
Nitrogen, wt-%	0.17	2.19	1.90	0.06	1.42	1.09	0.09
C <sub>7</sub> Insolubles, wt-%	4.67	0.44	0.14	0.01	0.26	0.01	0.01
Toluene Insolubles, wt-%	< 0.01	0.01	< 0.01	0.01	< 0.01	0.01	< 0.01
Viscosity at 100°F, SUS	118.5	213	156.0	54.2	186.7	124.6	60.1
Viscosity at 100°F, cSt	24.80	45.72	33.23	8.633	39.98	26.20	10.35
Steam Jet Gum, mg/100 mL	35,875.0	26,463.0	22,129.0	5,668.1	21,314.8	16,940.5	7,823.5
Bromine Number	2.4	30.2	15.8	0.8	19.4	7.8	1.9
Nickel, ppm	13	3.5	3.0	< 0.1	8.8	3.2	< 0.1
Vanadium, ppm	47	0.5	0.5	< 0.1	0.5	< 0.2	< 0.2
Iron, ppm	2.8	108	13	< 0.3	53	14	< 0.1
Arsenic, ppm	< 1	30	< 1	< 1	28	< 1	< 1
Conradson Carbon, wt-%	7.98	2.35	1.57	0.01	1.05	0.44	0.03

TABLE 47. PARAHO SHALE OIL-PETROLEUM OIL

Compatibility/Stability Study

Name	Heavy Arabian Crude	30% Paraho Shale Oil/ 70% Heavy Arabian Crude				Paraho Shale Oil	
		First-Stage		Second-Stage		First-Stage	Second-Stage
		Raw	Hydrotreated	Raw	Hydrotreated	Hydrotreated	Hydrotreated
<u>Initial Analysis:</u>							
C <sub>7</sub> Insolubles, wt-%	4.67	3.23	3.24	3.30	0.44	0.14	0.01
Toluene Insolubles, wt-%	< 0.01	< 0.01	0.01	< 0.01	0.01	< 0.01	0.01
Viscosity at 100°F, SUS	118.5	130.6	124.5	86.9	213	156	54.2
<u>Stability Test Analysis:</u>							
Du Pont F-21-61							
C <sub>7</sub> Insolubles, wt-%	5.92	3.38	3.28	3.60	0.40	0.2	< 0.01
Toluene Insolubles, wt-%	0.07	0.01	0.01	< 0.01	< 0.01	0.01	0.01
Viscosity at 100°F, SUS	190.9	178.9	162.1	111.5	268	183.7	56.3
D-2274 16-hr Heat Treatment							
C <sub>7</sub> Insolubles, wt-%	6.23	5.17	4.23	4.19	1.70	0.79	0.02
Toluene Insolubles, wt-%	< 0.01	0.01	< 0.01	< 0.01	< 0.01	0.01	< 0.01
Viscosity at 100°F, SUS	214	246	194.3	115.9	325	205	55.4
Adherent Gum, mg/100 mL	1.2	10.6	2.2	0.9			
3-months Dark Storage, 110°F							
C <sub>7</sub> Insolubles, wt-%	6.07	4.48	4.12	4.14	0.97	0.29	0.01
Toluene Insolubles, wt-%	0.01	< 0.01	< 0.01	< 0.01	< 0.01	0.01	< 0.01
Viscosity at 100°F, SUS	381	358	286	115.4	311	171	55.5
Adherent Gum, mg/100 mL	0.5	2.1	0.3	0.2	0.5	0.8	0.8

TABLE 48. OCCIDENTAL SHALE OIL/PETROLEUM OIL

Compatibility/Stability Study

Name	Heavy Arabian Crude	30% Occidental Shale Oil/ 70% Heavy Arabian Crude			Occidental Shale Oil		
		Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated	Raw	First-Stage Hydrotreated	Second-Stage Hydrotreated
<u>Initial Analysis:</u>							
C <sub>7</sub> Insolubles, wt-%	4.67	3.21	3.00	3.28	0.26	0.01	0.01
Toluene Insolubles, wt-%	< 0.01	< 0.01	0.02	< 0.01	< 0.01	0.01	< 0.01
Viscosity at 100°F, SUS	118.5	132.5	115.6	89.7	186.7	124.6	60.1
<u>Stability Test Analysis:</u>							
Du Pont F-21-61							
C <sub>7</sub> Insolubles, wt-%	5.92	3.38	3.39	3.51	0.50	0.40	0.01
Toluene Insolubles, wt-%	0.07	< 0.01	0.01	< 0.01	0.01	0.01	0.01
Viscosity at 100°F, SUS	190.9	169.7	146.7	107.9	210	135	63.6
D-2274 16-hr Heat Treatment							
C <sub>7</sub> Insolubles, wt-%	6.23	4.95	3.94	4.17	3.18	0.11	< 0.01
Toluene Insolubles, wt-%	< 0.01	< 0.01	< 0.01	< 0.01	0.01	< 0.01	< 0.01
Viscosity at 100°F, SUS	214	209	169.5	119.4	260	140.1	62.2
Adherent Gum, mg/100 mL	1.2	2.4	0.4	1.7		0.9	1.1
3-months Dark Storage, 110°F							
C <sub>7</sub> Insolubles, wt-%	6.07	4.68	3.97	4.17	0.88	0.03	< 0.01
Toluene Insolubles, wt-%	0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01	< 0.01
Viscosity at 100°F, SUS	381	329	244	163.5	221	131.6	59.7
Adherent Gum, mg/100 mL	0.5	0.9	0.3	0.3	0.7	0.1	0.2

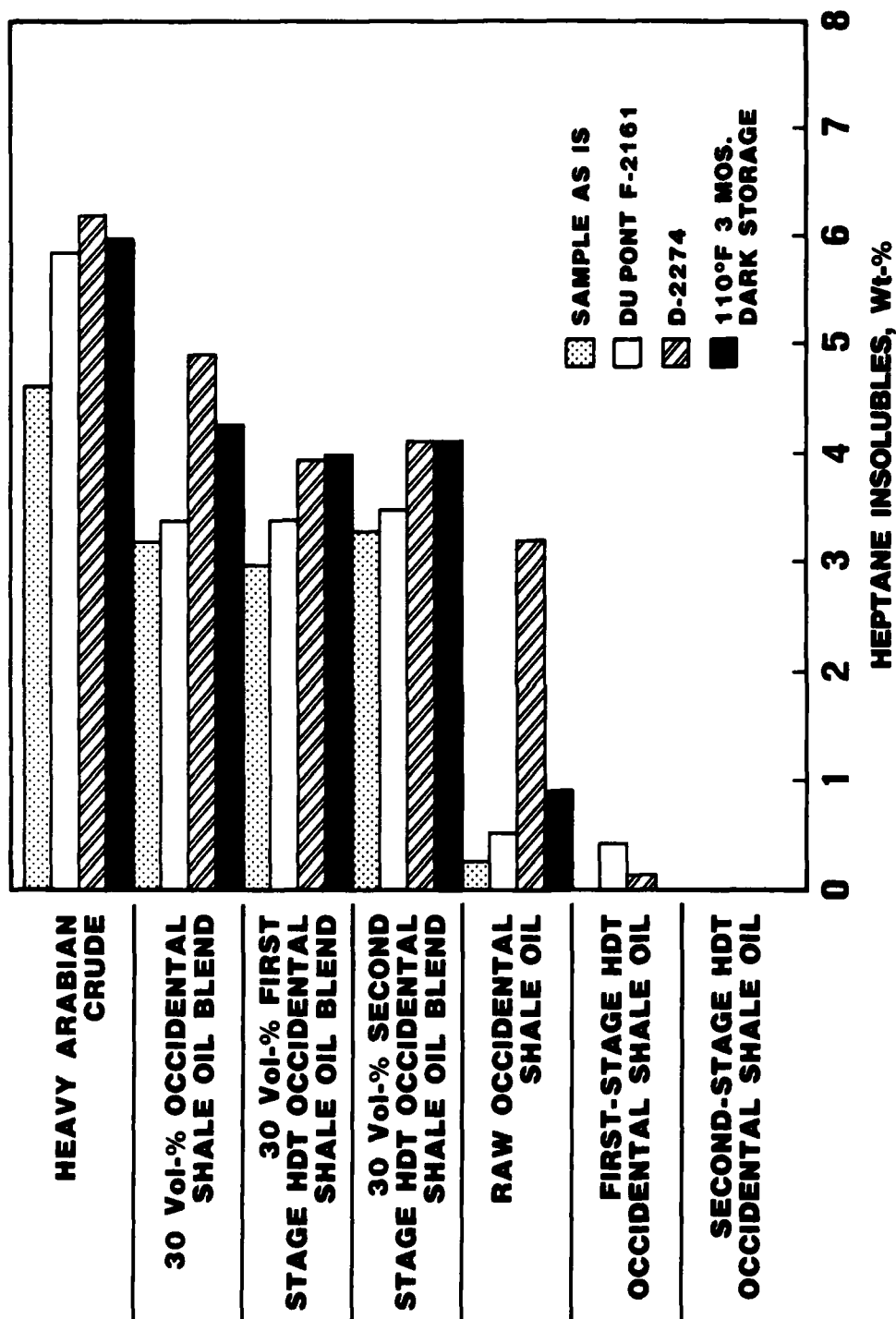
TABLE 49. SHALE OIL COMPATIBILITY/STABILITY STUDY

Comparison of Analyzed and Calculated Values for Shale Oil and Petroleum Blends

<u>Shale Oil Component in Blend</u>	<u>Analytical</u>		<u>Calculated</u>	
	<u>cSt Viscosity</u>		<u>cSt Viscosity</u>	
			<u>RE I-4</u>	<u>Refutas</u>
30 Vol-% Raw Paraho Shale Oil	27.54		29.2	29.66
30 Vol-% Paraho Shale Oil First-Stage Hydrotreated	25.17		26.9	27.03
30 Vol-% Paraho Shale Oil Second-Stage Hydrotreated	17.38		17.5	17.59
30 Vol-% Raw Occidental Shale Oil	27.97		28.0	28.55
30 Vol-% Occidental Shale Oil First-Stage Hydrotreated	24.15		25.2	25.2
30 Vol-% Occidental Shale Oil Second-Stage Hydrotreated	18.06		18.8	18.73

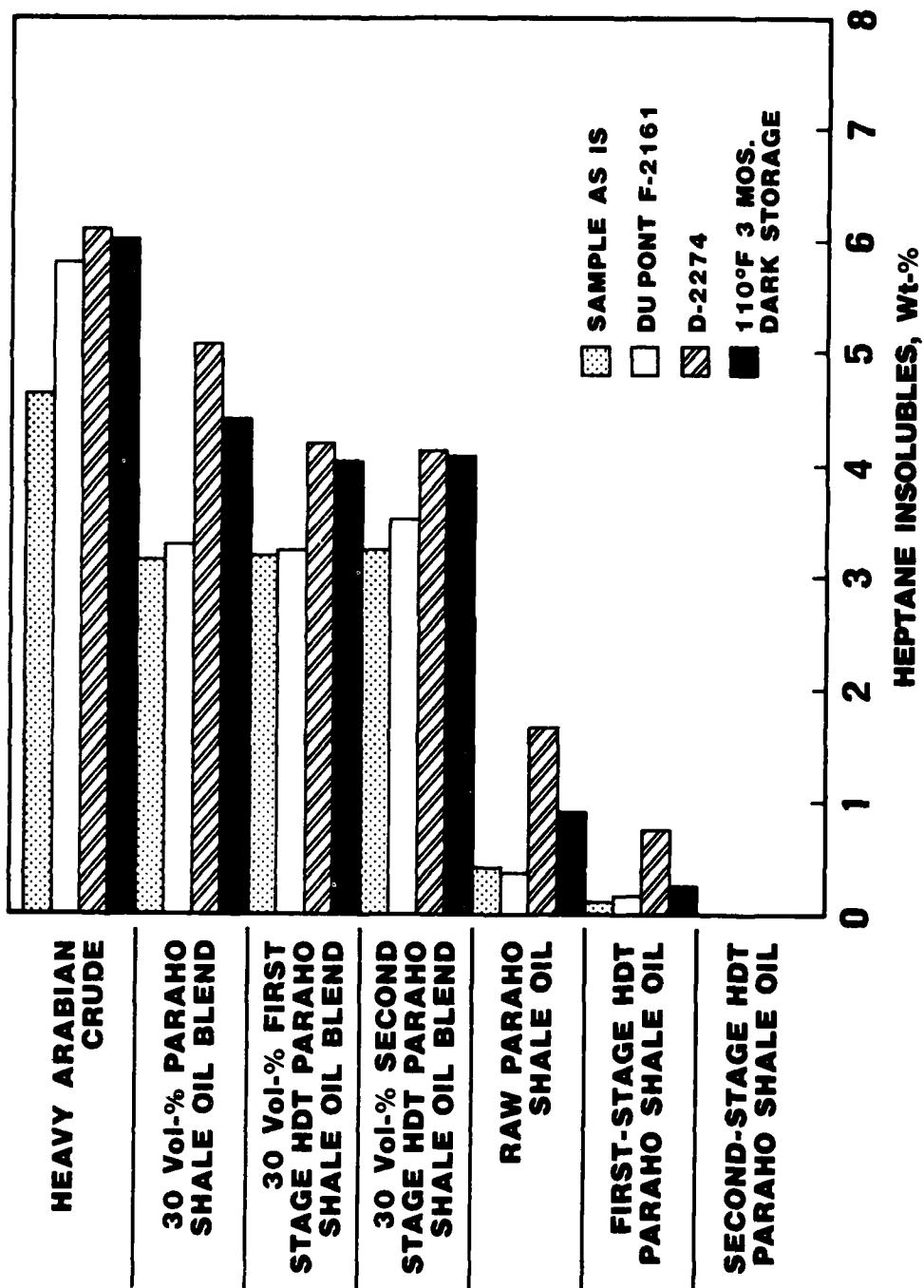
	<u>Analytical</u>		<u>Calculated</u>	
	<u>C7</u>	<u>Toluene</u>	<u>C7</u>	<u>Toluene</u>
	<u>Insol.,</u>	<u>Insol.,</u>	<u>Insol.,</u>	<u>Insol.,</u>
	<u>Wt-%</u>	<u>Wt-%</u>	<u>Wt-%</u>	<u>Wt-%</u>
30 Vol-% Raw Paraho Shale Oil	3.23	<0.01	3.36	<0.01
30 Vol-% Paraho Shale Oil First-Stage Hydrotreated	3.24	0.01	3.29	<0.01
30 Vol-% Paraho Shale Oil Second-Stage Hydrotreated	3.30	<0.01	3.31	<0.01
30 Vol-% Raw Occidental Shale Oil	3.21	<0.01	3.32	<0.01
30 Vol-% Occidental Shale Oil First-Stage Hydrotreated	3.00	0.02	3.27	<0.01
30 Vol-% Occidental Shale Oil Second-Stage Hydrotreated	3.28	<0.01	3.31	<0.01



UOP 734-16

FIGURE 27

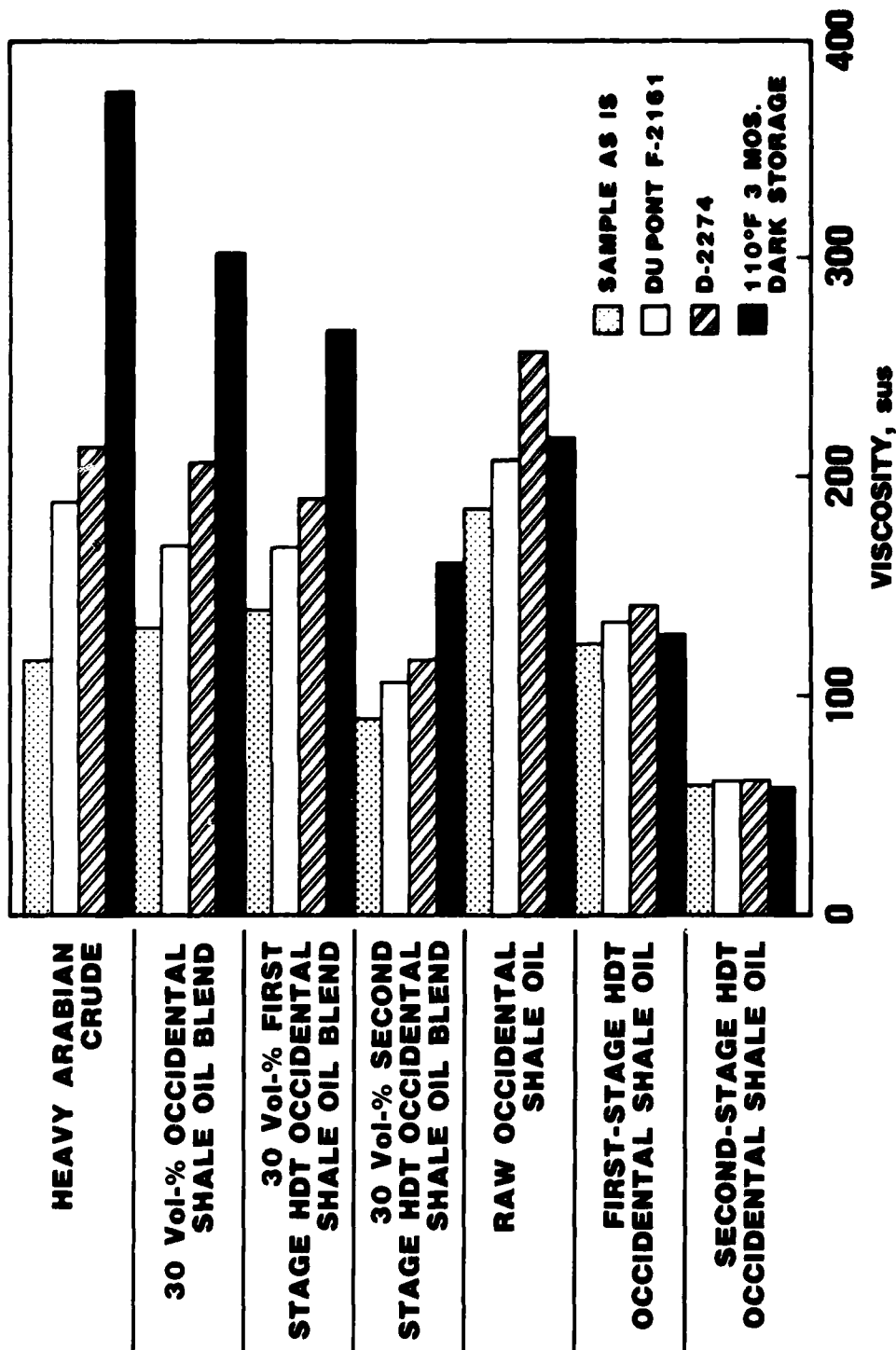
## EFFECT OF STORAGE ON HEPTANE INSOLUBLES OCCIDENTAL SHALE OIL STUDY



UOP 734-17

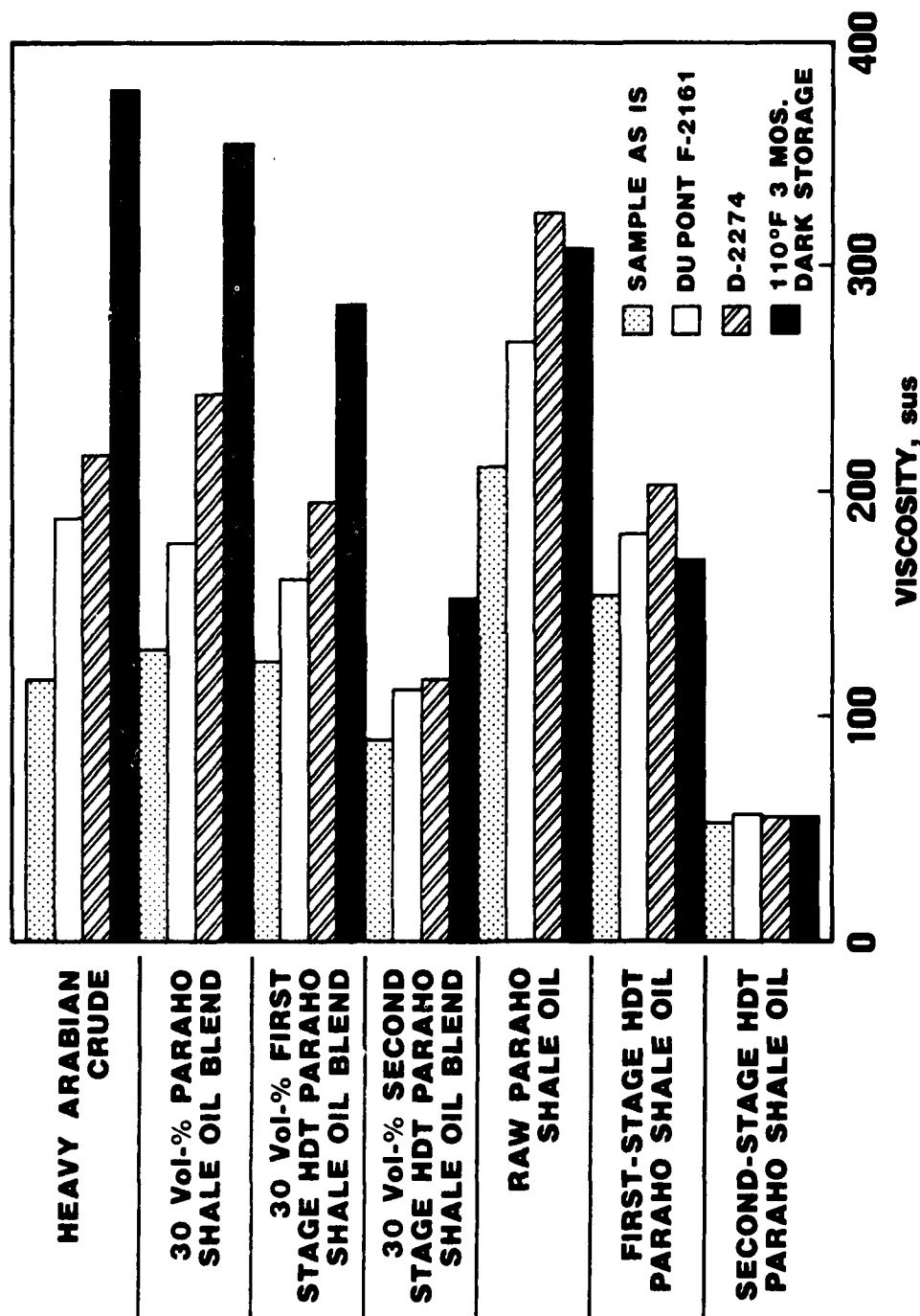
**FIGURE 28**

# **EFFECT OF STORAGE ON HEPTANE INSOLUBLES PARAHO SHALE OIL STUDY**



UOP 34 15

**FIGURE 29**  
**EFFECT OF STORAGE ON VISCOSITY**  
**OCCIDENTAL SHALE OIL STUDY**



UOP 734-18

**FIGURE 30**  
**EFFECT OF STORAGE ON VISCOSITY**  
**PARAHO SHALE OIL STUDY**

## SECTION VIII

### SHALE OIL UPGRADING ECONOMICS

In addition to selecting a novel conversion processing scheme for high jet fuel yield, the proposed flow scheme will provide a realistic and economical solution to the problem of shale oil conversion. The UOP processing scheme, as shown in Figure 31, provides for the removal of arsenic and stabilization of the raw shale oil in a relatively moderate, first-stage pretreatment step. Denitrification is accomplished in a more severe, second-stage hydrotreatment. Finally, the upgraded shale oil is converted to transportation fuels in the hydrocracker. Hydrocracker jet and diesel fuel products do not require further treatment.

#### Study Basis

The basis for establishing the processing scheme and developing reliable estimates of external requirements and investment costs for the key processing units includes the following:

- A. The refinery design and flow schemes are based on processing 100,000 barrels per stream day (BPSD) of desalted and deashed Occidental shale oil, described in Table 50.
- B. Two primary products -- JP-4 and JP-8 aviation turbine fuels -- are required. Coproducts such as various grades of diesel fuel, fuel oil, motor gasoline, aviation gasoline, or other grades of turbine fuel may be produced.
- C. Only commercially proven processes are to be considered in the refinery processing schemes.
- D. There are no outside feed streams to be processed with the raw shale oil. Fuels for heating are to be internally generated.

E. The refinery is assumed to be a grassroots facility located at a Rocky Mountain site.

F. Capital Investment

1. Western U.S. location
2. 100,000 BPSD crude shale oil capacity
3. First quarter 1981 cost base
4. 100% equity financing
5. Investment timing over a three year construction period
  - a. 25% first year
  - b. 50% second year
  - c. 25% third year
6. 10% investment tax credit
7. 45% of plant onsites (not including feed and product storage) will be used to generate plant offsite cost.

G. Working Capital

1. 21 days crude storage capacity with 14 days crude inventory
2. 14 days product storage capacity with 7 day product inventory
3. Crude shale oil valued at \$40.00 per barrel
4. Product valued at determined cost
5. Debt financed at 15%

H. Capital Return

1. 15% DCF rate of return on capital
2. 13 years sum of years digits depreciation
3. Zero salvage value

I. Operating Basis

1. 16 year plant operating life
2. 50% operating capacity first year, 100% thereafter
3. 90% on-stream factor

4. 100,000 BPSD capacity
5. All process fuel/heat requirements shall be generated internally from the original shale oil feed.

J. Operating Cost Basis

1. Crude Shale Oil -- \$40.000 per barrel
2. Cooling Water -- \$0.03 per 1000 gal
3. Electricity -- \$0.045 per kWh
4. Operators -- \$12.00 per hour
5. Helpers -- \$10.50 per hour
6. Labor Supervision -- 25% of direct labor
7. Overhead -- 100% of direct labor
8. Federal and State Taxes -- 50%
9. Maintenance, Local Taxes and Insurance -- 4.5% of fixed investment
10. Product Values -- all liquid fuel products are of equal value
11. By-product Values
  - a. Ammonia at \$155/short ton
  - b. Sulfur at \$105/long ton

K. Miscellaneous

1. Use English units
2. Mass flow rates
  - a. Barrels per stream. day (BPSD)
  - b. Short tons per day (ST/D)
  - c. Standard cubic feet per day (SCFD)

Refinery Processing Scheme

The processing scheme for the production of JP-4 and JP-8 jet fuels, shown in Figures 32 and 33, respectively, are nearly identical except for the size of the units. Naphtha hydrotreating and Platforming units are added to the flow scheme when producing JP-8, and a partial oxidation unit

is added to supplement the hydrogen plant when producing the JP-4 in the diesel fuel case. Various combinations of jet fuel and diesel fuel are produced by utilizing the same flow schemes and by varying the hydrocracking severity to produce the desired product slate. Overall material balances for all cases for JP-4 and JP-8 jet fuels are shown in Table 51.

#### First-Stage Hydrotreating (UOP RCD Unibon)

The desalted shale oil charge stock is combined with amine scrubbed recycle hydrogen gas plus make-up hydrogen gas (from the hydrogen plant), heated to the desired reaction temperature, by means of exchange and direct fired heaters, and charged to the reactors. The reactor effluent, after heat exchange with the incoming feed, is water washed, condensed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is amine treated and recycled to the reactor section. Ammonia-rich water is removed from the separator and sent to the sour water stripper. Liquid hydrocarbon product from the separator is not stripped or fractionated but pumped directly into the high-pressure, second-stage hydrotreater.

The first-stage hydrotreater saturates the olefins and diolefins by contacting the feedstock with high purity hydrogen over a catalyst bed. Iron and arsenic are removed along with most of the sulfur compounds. Essentially no arsenic and only small amounts of unsaturates remain; however, a high concentration of nitrogen compounds is still present in the first-stage product and must be removed in the more severe second-stage hydrotreating step.

#### Second-Stage Hydrotreating

The first-stage separator liquid is combined with the recycle hydrogen-rich gas plus make-up hydrogen (from the hydrogen plant), heated to the desired reactor temperature, by means of exchange and direct fired heaters, and charged to the reactors. The reactor effluent is heat exchanged with the reactor feed, water washed, condensed, cooled and sent to the product separator. The hydrogen-rich gas from the separator is

recycled to the reactor, and the ammonia-rich water is drawn from the separator and treated in the sour water stripper. Liquid hydrocarbons from the separator are pressured directly to the hydrocracking unit (HC Unibon) for further processing.

The second-stage hydrotreating step completes the denitrification of the shale oil to less than 1000 wt-ppm. Hydrocarbon liquid to be used as an environmentally acceptable fuel oil for process heaters is drawn from the high-pressure hydrotreater separator. This material will be stripped, with the light ends going to fuel gas treating and the bottoms liquid used as fuel oil. The balance of the high pressure separator liquid will be used as hydrocracker feedstock. The two-stage hydrotreating yields are given in Table 52.

#### Hydrocracking (HC Unibon)

Hydrocracking is a highly versatile process for the conversion of a variety of petroleum/hydrocarbon fractions to yield more valuable, lower-boiling products. Along with the molecular weight reduction accomplished in the hydrocracking reactions, there is almost complete conversion of sulfur-, nitrogen- and oxygen-containing compounds, thus yielding products that are mixtures of essentially only paraffins, naphthenes and aromatics. The kerosine products yielded from the HC Unibon unit are of good quality. Both kerosine cuts (JP-4 and JP-8) are nearly sulfur free, low in aromatics, have low freeze points and good smoke points. These hydrocracked kerosines make good jet fuel blending stock.

The HC Unibon unit proposed for this refinery is a parallel-flow hydrocracker designed to process the hydrotreated Occidental shale oil into light ends, light and heavy naphthas and kerosine/diesel products. Several operational modes vary the end points on the kerosine to make the JP-4 or JP-8 jet fuels and the DF-2/DFM diesels. Tables 53 through 56 present the yield estimates and product properties when operating for JP-4 and JP-8 jet fuels including the alternative diesel cases.

The hydrotreated shale oil charge stock is combined with the recycle hydrogen-rich gas plus hydrogen make-up, heated to the desired reactor temperature by means of heat exchange and a direct fired heater, and charged to the reactor section. The reactor section effluent is water washed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is returned to the reactor section as recycle gas and hydrogen quench.

Ammonia is removed from the product separator with the wash water. The hydrocarbon liquid from the separator is flashed to the low pressure flash drum where much of the  $H_2S$  and light gases are removed to the fuel gas treating system. The low-pressure, flash hydrocarbon liquid is charged to a fired heater and sent to the product fractionator where the IBP-300°F material is taken overhead, the 300-520°F kerosine is stripped and blended with the  $C_5+$  naphtha product from the overhead material into JP-4 jet fuel. For the JP-8 jet fuel case, a 300-550°F kerosine is stripped for flash point and sent to the product storage. When diesel products are required with the jet fuels, a lower side-cut draw is made on the product fractionator, and a side-cut stripper is provided to make flash point. The product fractionator bottoms material is combined with recycle hydrogen gas and make-up hydrogen and charged to the reactor section. Utilities consumption figures can be found in Tables 62 through 65, and capacities and investments are shown in Table 66.

#### Light Ends Fractionation

The product fractionator overhead material is cooled, condensed and then collected in the overhead receiver. The overhead receiver gas is compressed and recontacted with the overhead naphtha liquid in the recontact drum. Net gas is removed to fuel gas treating, and the naphtha is sent to the naphtha splitter, where  $C_6$  minus material is taken overhead and the  $C_7$ -300°F heavy naphtha is taken as bottoms product for blending into the JP-4 jet fuel, or used as feed to the naphtha hydrotreater and Platformer to make high octane gasoline when the plant is making JP-8 jet fuel. The naphtha splitter overhead ( $C_6$ -) material is charged to a debutanizer to remove  $C_4$ - material from the light naphtha ( $C_5/C_6$ ). The

debutanized light naphtha is blended with the heavy naphtha (C7-300°F) and kerosine (300-520°F) to make JP-4, the wide-cut jet fuel or the light naphtha is blended into the gasoline pool with high-octane Platformate produced during the JP-8 jet fuel production. If required, part of the light naphtha can be utilized in the hydrogen plant as fuels/feedstock. A small depropanizer is used to separate the C<sub>3</sub> and lighter material from the butanes in the C<sub>4</sub>-overhead liquid from the debutanizer. The depropanizer bottoms butanes are used to make vapor pressure in the gasoline during the JP-8 operation. Leftover light ends are sent to fuel gas treating prior to being used as hydrogen plant feedstock. Utilities consumption figures can be found in Tables 62 through 65, and capacities and investments are shown in Table 66.

#### Naphtha Hydrotreating (For JP-8 Cases Only)

The C7-300°F hydrocracked naphtha from the bottoms of the naphtha splitter is charged to the naphtha hydrotreater, for complete desulfurization and other contaminant removal (oxygen and nitrogen), prior to reforming in a UOP Platforming unit. The naphtha is combined with hydrogen-rich recycle gas plus make-up hydrogen gas, heated to the desired reaction temperature by means of exchange and direct fired heater, and charged to the reactor. The effluent from the reactor, after heat exchange with the incoming feed, is condensed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is recycled to the reactor section while net separator gas is sent to fuel gas.

The liquid product from the separator is sent to a stripper column for hydrogen sulfide and light ends removal. The C<sub>6</sub> plus stripper bottoms product is charged directly to the Platformer. Table 57 shows the naphtha hydrotreater yield estimate, while Tables 64 and 65 list the utilities. Table 66 presents the plant capacities and investment costs.

#### UOP Platforming (For JP-8 Cases Only)

In the UOP Platforming unit the hydrotreated naphtha is combined with the recycle hydrogen-rich gas stream, heated by means of exchange and a

The hydrotreated shale oil charge stock is combined with the recycle hydrogen-rich gas plus hydrogen make-up, heated to the desired reactor temperature by means of heat exchange and a direct fired heater, and charged to the reactor section. The reactor section effluent is water washed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is returned to the reactor section as recycle gas and hydrogen quench.

Ammonia is removed from the product separator with the wash water. The hydrocarbon liquid from the separator is flashed to the low pressure flash drum where much of the  $H_2S$  and light gases are removed to the fuel gas treating system. The low-pressure, flash hydrocarbon liquid is charged to a fired heater and sent to the product fractionator where the IBP-300°F material is taken overhead, the 300-520°F kerosine is stripped and blended with the  $C_5+$  naphtha product from the overhead material into JP-4 jet fuel. For the JP-8 jet fuel case, a 300-550°F kerosine is stripped for flash point and sent to the product storage. When diesel products are required with the jet fuels, a lower side-cut draw is made on the product fractionator, and a side-cut stripper is provided to make flash point. The product fractionator bottoms material is combined with recycle hydrogen gas and make-up hydrogen and charged to the reactor section. Utilities consumption figures can be found in Tables 62 through 65, and capacities and investments are shown in Table 66.

#### Light Ends Fractionation

The product fractionator overhead material is cooled, condensed and then collected in the overhead receiver. The overhead receiver gas is compressed and recontacted with the overhead naphtha liquid in the recontact drum. Net gas is removed to fuel gas treating, and the naphtha is sent to the naphtha splitter, where  $C_6$  minus material is taken overhead and the  $C_7$ -300°F heavy naphtha is taken as bottoms product for blending into the JP-4 jet fuel, or used as feed to the naphtha hydrotreater and Platformer to make high octane gasoline when the plant is making JP-8 jet fuel. The naphtha splitter overhead ( $C_6$ -) material is charged to a debutanizer to remove  $C_4$ - material from the light naphtha ( $C_5/C_6$ ). The

debutanized light naphtha is blended with the heavy naphtha (C<sub>7</sub>-300°F) and kerosine (300-520°F) to make JP-4, the wide-cut jet fuel or the light naphtha is blended into the gasoline pool with high-octane Platformate produced during the JP-8 jet fuel production. If required, part of the light naphtha can be utilized in the hydrogen plant as fuels/feedstock. A small depropanizer is used to separate the C<sub>3</sub> and lighter material from the butanes in the C<sub>4</sub>- overhead liquid from the debutanizer. The depropanizer bottoms butanes are used to make vapor pressure in the gasoline during the JP-8 operation. Leftover light ends are sent to fuel gas treating prior to being used as hydrogen plant feedstock. Utilities consumption figures can be found in Tables 62 through 65, and capacities and investments are shown in Table 66.

#### Naphtha Hydrotreating (For JP-8 Cases Only)

The C<sub>7</sub>-300°F hydrocracked naphtha from the bottoms of the naphtha splitter is charged to the naphtha hydrotreater, for complete desulfurization and other contaminant removal (oxygen and nitrogen), prior to reforming in a UOP Platforming unit. The naphtha is combined with hydrogen-rich recycle gas plus make-up hydrogen gas, heated to the desired reaction temperature by means of exchange and direct fired heater, and charged to the reactor. The effluent from the reactor, after heat exchange with the incoming feed, is condensed, cooled and sent to the product separator. The hydrogen rich off-gas from the separator is recycled to the reactor section while net separator gas is sent to fuel gas.

The liquid product from the separator is sent to a stripper column for hydrogen sulfide and light ends removal. The C<sub>6</sub> plus stripper bottoms product is charged directly to the Platformer. Table 57 shows the naphtha hydrotreater yield estimate, while Tables 64 and 65 list the utilities. Table 66 presents the plant capacities and investment costs.

#### UOP Platforming (For JP-8 Cases Only)

In the UOP Platforming unit the hydrotreated naphtha is combined with the recycle hydrogen-rich gas stream, heated by means of exchange and a

fired heater, then charged successively through the reforming reactors. Fired interheaters are provided between the reactors in order to achieve the desired reactor inlet temperatures.

The effluent from the last reactor, after heat exchange with the incoming feed, is condensed, cooled and sent to the product separator. The hydrogen-rich gas stream from the separator is recycled to the reactor section while the off-gas produced is used as make-up hydrogen for the naphtha hydrotreater and as feedstock to the hydrogen plant. The separator hydrocarbon liquid after recontacting with the compressed separator gas, is separated and charged to the stabilizer (debutanizer for motor fuel operation) where the light hydrocarbons are taken overhead to hydrocracker fractionation and the C<sub>5</sub>+ Platformate is sent to gasoline blending.

The UOP Platformer is designed for processing C<sub>7</sub>-300°F naphtha in a conventional fixed bed, semi-regenerative type reformer, featuring low pressure operation with gas recontacting giving maximum liquid recovery and high hydrogen purity. The yields and some of the major properties are noted in Table 58. The units are designed for 100 RON clear Platformate for the maximum JP-8 case, and 98 RON clear Platformate for the JP-8 plus diesel case. The Platformer is designed for conventional catalyst regeneration with an estimated first cycle length of twelve months.

The liquid C<sub>4</sub>- material from the Platformer debutanizer is sent to the depropanizer in the fractionation section to recover butanes for gasoline blending. There is no attempt to recover propane, and all the light end hydrocarbons are taken to the fuel gas system for feed to the hydrogen plant. Part of the hydrogen produced from the Platformer net separator gas is used in the naphtha hydrotreater and the balance of the gas, the larger portion, feeds the hydrogen plant. Tables 64 and 65 present the utilities consumption, and Table 66 shows the capacities and investment requirements for the UOP Platforming unit.

## Hydrogen Plant

A hydrogen plant is required to supply 97% hydrogen to operate the hydrogen consuming process units. Estimated hydrogen requirements and hydrogen plant sizes and yields are given in Table 59 for JP-4 cases and Table 60 for JP-8 cases.

The preferential feedstock to the hydrogen plant is treated fuel gas but where fuel gas is in short supply, light naphtha ( $C_5/C_6$ ) is then used as a supplement. In the JP-4 plus diesel case, there is not enough fuel gas or light naphtha available, so a partial oxidation plant is used to obtain the balance of the hydrogen.

The basic steps for the steam-hydrocarbon reforming process in the production of hydrogen are desulfurization, two-stage CO conversion, CO<sub>2</sub> removal, methanation and compression to the required pressure levels.

A variety of feedstocks can be used, such as natural gas, methane, ethane, propane and butanes. Liquid feeds such as light naphthas are sometimes used. The feed should contain less than 0.5% olefins to prevent carbon formation. The hydrocarbons are charged to the charcoal absorber for sulfur removal then sent to the reformer furnace with steam. The gas is converted largely to hydrogen, CO and CO<sub>2</sub>. The gases are cooled by the addition of steam or condensate and all are passed over catalyst in the CO converter. About 90 to 95% of the CO is converted to CO<sub>2</sub>. The hot gases leaving the converter are cooled and then scrubbed with an amine solution to remove most of the CO<sub>2</sub>. The gases are heated up after leaving the CO<sub>2</sub> absorber by exchange with gas coming from the CO converter and pass over catalyst in the methanator. Here all the carbon oxides are converted to methane by reaction with hydrogen. The product hydrogen gas from the methanator, saturated with water vapor, is cooled to 100°F.

Tables 62, 63, 64, 65 and 66 list the hydrogen plant utilities requirement, capacities and investment cost for each case.

#### Partial Oxidation (For JP-4 plus Diesel Case Only)

Even with lower hydrogen consumption in the JP-4 plus diesel case, the reduced supply of light feedstock (fuel gas and light naphtha) indicates that a partial oxidation unit is needed to supplement the hydrogen production from the steam reformer. The partial oxidation process is very flexible in regard to feedstocks. Residual oils from 1 to 10 °API gravity have routinely been processed. Raw shale oil could conceivably be used as feed but, because of the high arsenic content and other contaminants, the resulting hydrogen gas may be of poor quality. To avoid this problem, hydrotreated shale oil is used as the feedstock.

The treated shale oil is vaporized and mixed with oxygen and steam in the reactor. The first reaction phase is that of heating and cracking the hydrocarbon and dispersing it into oxygen (supplied by an air separation plant included in the scheme) and steam which acts as a moderator. In the second phase of reaction, the hydrocarbon burns when it reaches ignition temperature. The residence time is insufficient for complete combustion of the hydrocarbon, consequently one of the by-products is soot. A direct quench cools the gas and scrubs out the soot in a scrubber which is followed by the CO conversion step. The final composition of the product gas containing carbon dioxide and hydrogen is determined by the equilibrium condition of the shift reaction. The shift reaction is followed by carbon dioxide removal and a final methanation step to obtain the high purity hydrogen as a final product.

Estimated yields for the partial oxidation unit are shown in Table 61. Tables 63 and 66 show the partial oxidation unit utilities consumption, capacity and investment cost.

#### Amine Treating and Sulfur Recovery

Amine treating of refinery gases removes hydrogen sulfide and other acid gas constituents thus avoiding atmospheric pollution by SO<sub>2</sub> from combustion of these gases. The amine treating process is based on an absorption-regeneration cycle using aqueous solutions of an alkanolamine

which reacts with acid gases. Hydrogen sulfide containing feed is contacted counter-currently with amine solution in an absorption or extraction column. Regenerated amine solution is fed into the top of the column and the rich solution taken from the bottoms through exchange to regeneration, where the acid gases are stripped with steam and recovered as hydrogen sulfide with the regenerated solution recycled back to the absorber. The hydrogen sulfide from the amine unit and sour water from the sour water stripper are charged to a Claus sulfur recovery unit for conversion to elemental sulfur.

The low-pressure hydrotreater (RCD Unibon) recycle gas and the net off-gases from the HC Unibon and naphtha hydrotreater are amine treated for hydrogen sulfide removal. The off-gases are treated prior to being used as feedstock in the hydrogen plant or fuel gas to the heaters. In these processing schemes most of the treated light gases are used as hydrogen plant feedstock with little left over for heating.

#### Sour Water Treating

In the hydrocracking and hydrotreating processing units, water is injected to prevent build-up of salts on the surface of heat exchange tubes. Wash water used to dissolve ammonia and some hydrogen sulfide cannot be disposed of in the conventional refinery sewer system because of its chemical content. This sour water is charged to a stripper where hydrogen sulfide and ammonia are steam stripped from the water. The stripped water is returned to the refinery and the released gases, hydrogen sulfide and ammonia, are separated with the hydrogen sulfide processed in the sulfur plant for elemental sulfur and the ammonia recovered in a liquefaction plant.

#### Recovered Products

#### Aviation Turbine Fuels

The refinery is designed to produce two types of aviation turbine fuels as the major products. These are:

A. JP-4 Jet Fuel -- This military jet fuel is wide-cut with a distillation range from C<sub>5</sub>-518°F and with gravity limitations between 45-57 °API. Table 67 compares the product qualities of the various cases with the Military Specifications for JP-4. The maximum JP-4 case product meets these specifications, but the JP-4 in the JP-4 plus diesel case has a slightly higher distillation than allowed in the specification. The compositions of the JP-4 jet fuels are:

<u>Component</u>	<u>Max. JP-4 Case</u>			<u>JP-4 + Diesel Case</u>		
	<u>BPSD</u>	<u>ST/D</u>	<u>°API</u>	<u>BPSD</u>	<u>ST/D</u>	<u>°API</u>
Lt. Naph. (C <sub>5</sub> /C <sub>6</sub> )	11,819	1,375.1	81.4	5,601	649.7	82.1
C <sub>7</sub> -300°F Naph.	7,100	947.3	54.2	3,047	406.6	54.2
300-520°F Kero.	<u>72,841</u>	<u>10,230.7</u>	<u>44.9</u>	<u>45,307</u>	<u>6,363.5</u>	<u>44.9</u>
TOTAL	91,760	12,553.1	49.6	53,955	7,419.8	48.7

B. JP-8 Jet Fuel -- This military jet fuel is of the kerosine type, similar to ASTM Jet A-1 fuel, with a maximum distillation end point of 572°F, and with gravity limitations between 37-51 °API. Table 67 shows a comparison between the estimated product for each case with the JP-8 Military Specification. The jet fuel product does meet, or exceed, these specifications. The quantity and quality of the JP-8 jet fuels are:

<u>Component</u>	<u>Max. JP-8 Case</u>			<u>JP-8 + Diesel Case</u>		
	<u>BPSD</u>	<u>ST/D</u>	<u>°API</u>	<u>BPSD</u>	<u>ST/D</u>	<u>°API</u>
300-550°F Kero.	80,742	11,380.1	44.3	55,219	7,782.8	44.3

#### Diesel Fuels

In the alternative cases for JP-4 and JP-8, diesel fuels are produced along with the respective jet fuels. The diesel fuels recovered from these cases satisfy both the DF-2 Diesel and Marine Diesel Specifications. As noted in Table 68, the JP-4 + DF-2/DFM and JP-8 + DF-2/DFM diesels are very similar except for slight differences in properties. The quantity and composition of the diesel fuels are:

<u>Component</u>	<u>JP-4 + DF-2/DFM Case</u>			<u>JP-8 + DF-2/DFM Case</u>		
	<u>BPSD</u>	<u>ST/D</u>	<u>°API</u>	<u>BPSD</u>	<u>ST/D</u>	<u>°API</u>
520-700°F Diesel	36,871	5,376.9	38.4	-	-	-
550-700°F Diesel	-	-	-	29,883	4,373.0	37.8

#### Motor Gasoline Fuels

Motor gasolines are produced only when JP-8 jet fuels are made. The motor gasoline blended in this study is special grade unleaded, which meets Military Specification and Federal Specification VV-G-1690B dated July 1, 1978. Table 69 compares the study blends with the required specification and the blends equal, or exceed, these specifications. The composition of the gasoline blends is as follows:

#### Max. JP-8 Case Gasoline Blend

<u>Component</u>	<u>BPSD</u>	<u>ST/D</u>	<u>Sp. Gr.</u>	<u>RVP</u>	<u>RON</u> <u>Clear</u>	<u>MON</u> <u>Clear</u>	<u>R+M/2</u> <u>Clear</u>
Platformate	5,139	740.8	0.8233	4.0	100.0	88.6	
Lt. Naphtha	2,776	322.8	0.6643	11.0	75.0	73.0	
Mixed Butanes	<u>934</u>	<u>93.9</u>	<u>0.5743</u>	<u>-</u>	<u>98.5</u>	<u>94.3</u>	
TOTAL	8,849	1,157.5	0.7471	13.5	92.0	84.3	88.1

#### JP-8 + DF-2/DFM Case Gasoline Blend

<u>Component</u>	<u>BPSD</u>	<u>ST/D</u>	<u>Sp. Gr.</u>	<u>RVP</u>	<u>RON</u> <u>Clear</u>	<u>MON</u> <u>Clear</u>	<u>R+M/2</u> <u>Clear</u>
Platformate	2,337	333.8	0.8159	3.9	98.0	87.0	
Hvy. Naphtha	280	37.3	0.7620	0.3	59.0	57.0	
Lt. Naphtha	454	52.7	0.6625	11.0	75.0	73.0	
Mixed Butanes	<u>450</u>	<u>45.3</u>	<u>0.5743</u>	<u>-</u>	<u>98.5</u>	<u>94.3</u>	
TOTAL	3,521	469.1	0.7609	13.5	92.0	83.7	87.9

It should be noted that both grades of gasoline meet or exceed the octane requirements and the other properties required by the gasoline specs. The composition of these blends is toward a light gasoline with a large percentage of gasoline composed of light naphtha and butanes, but the blends are acceptable by the specifications.

### Refinery Fuel Gas

As the material balances shown in Table 51 indicate, no fuel gas is used for heating in any of the processing schemes. All the fuel gas is treated and sent to the hydrogen plant as feedstock.

### Refinery Fuel Oil

All heating will be done with fuel oil or naphtha that is not processed into gasoline. Fuel oil is drawn from the refinery processing scheme after the second-stage hydrotreater. The high-pressure separator liquid, drawn for fuel oil, is stabilized in the fuel oil stabilizer with the light hydrocarbon material going to fuel gas treating and the stabilized liquid used as fuel oil. The light naphtha used as fuel in the Max. JP-8 case can be burned in the hydrogen plant. Table 51, Overall Material Balance, indicates the quantities of fuel oil used in each case.

### Recovered By-Products

Sulfur -- Approximately 97.5 short tons per stream day of sulfur are recovered from the sulfur plant in each of the processing cases.

Ammonia -- Between 306-307 short tons per stream day of liquid ammonia are recovered from the ammonia liquefaction plant in each of the processing cases.

### Operating Cost

The overall refinery operating costs for the JP-4 and JP-8 cases are shown in Tables 70 through 72. Operating costs are divided into direct and indirect operating costs which are as follows:

#### Direct Operating Cost

Refinery Labor -- Refinery labor includes all the personnel for the process units hired at \$12.00 per hour for operators and \$10.50 per hour

for helpers. To arrive at a total labor cost, a 100% overhead allowance is added to these base rates. A 25% allowance for supervision is also made.

Maintenance Allowance -- The maintenance allowance covers normal operating maintenance and turnaround contract maintenance for all refinery equipment including process units, offsites and depreciable assets. An amount equal to 3% of erected plant investment is allocated for maintenance.

Utilities -- Refinery fuel is generated internally for both JP-4 and JP-8 cases. Power is purchased at \$0.045 per kWh, and cooling water is priced at \$0.03 per 1000 gallons. Boiler feed water is estimated at \$0.50 per 1000 pounds. Steam (600 psig) is generated at \$0.68 per 1000 pounds (fuel provided from internal sources). Cold treated water is purchased at \$0.07 per 1000 pounds. All utilities are consumed at normal average operating rates.

Catalyst, Solvents and Chemicals -- Catalyst consumption is based on the expected catalyst life for normal operating conditions. Similarly, solvents and chemicals are based on normal average operating usage.

#### Indirect Operating Cost

Local Taxes -- An allowance of 1% of erected plant investment, catalyst and working capital is allocated toward local taxes.

Insurance -- An allowance of 1/2% of erected plant investment, catalyst and working capital is allocated toward insurance.

#### Process Design, Capital Cost and Utilities

Process designs were prepared for the first- and second-stage hydrotreaters and for the primary conversion section, the hydrocracker. These designs were based on the yields and operating conditions developed from the specific laboratory and pilot plant data generated during the

earlier phases of this project. Each process design includes a heat and material balance, characteristics of principal equipment, and a detailed process flow diagram. The heat and material balance includes stream quantities (mass and volume) and compositions ( $H_2$ ,  $H_2S$ ,  $NH_3$ ,  $H_2O$ , light hydrocarbons), molecular weights, flowing densities and enthalpies entering and leaving each major equipment item, in addition to pressures and temperatures.

In order to provide more definitive cost data for these primary units, the process design was used as a basis for generating EFCEST (Engineering for Cost Estimating) data. EFCEST data provide a sufficient level of detailed project engineering work to appropriately describe the equipment required. The EFCEST data were then used to prepare a detailed cost estimate with an estimated precision of  $\pm 25\%$  for first quarter, 1981 U.S. Gulf Coast construction. To obtain a Western location construction cost, the Gulf Coast cost for plant and offsites were increased by 5%.

Material balances prepared for the naphtha hydrotreating and Platforming units, amine treating and sulfur recovery, sour water stripping, raw feed desalting, ammonia plant and hydrogen production units include stream quantities and compositions. Considering the extent of UOP experience with these types of units, reliable cost and utility estimates were provided without preparing EFCEST data and detailed cost estimates. The material and labor estimates provided for the above units were derived by scaling detailed estimates prepared for similar units.

In Table 66, the capacity and the estimated erected cost (EEC) for individual process units are shown. The costs for the JP-4 and JP-8 cases are similar with the exception that a naphtha hydrotreater and Platformer unit combination is included in the JP-8 case, and a partial oxidation unit is added to the JP-4 plus diesel case. The common facilities cost includes such items as buildings (process control house and substations), electrical power distribution, area lighting and site development in the process area.

Offsite costs are influenced more by the characteristics of the site, local regulations and policies of the refinery than by minor differences in process scheme. Allowances for offsite costs are included, with recognition of special requirements such as for waste treatment, where applicable. The offsite facility cost estimates were based on 45% of the plant onsite investment plus the cost of specified tankage capacity for storing crude and products. This basis was used to estimate offsite facility costs as no other design information was available. As such, the offsite cost is an order-of-magnitude cost estimate and has no meaningful accuracy range.

The capital investment summary for the JP-4 and JP-8 cases is presented in Table 74. The total capital investment is estimated to be  $\$902 \times 10^6$  for the maximum JP-4 case and  $\$939 \times 10^6$  for the maximum JP-8 case. For the alternative diesel cases, the JP-4 + DF-2/DFM case has a investment of  $\$989 \times 10^6$  and the JP-8 + DF-2/DFM case a  $\$905 \times 10^6$  investment.

Utility requirements are estimated from the process design data and the information provided for the auxiliary units. Utilities estimated include: electric power, fuel, steam at recommended pressure levels, boiler feedwater, condensate, cold process water and cooling water.

#### Linear Programming

The use of UOP's linear programming (LP) capabilities permitted the evaluation of numerous processing and product blending alternatives required in this shale oil upgrading study. The linear programming technique, using a multitude of mathematical calculations, allowed various alternatives to be quickly examined to determine the best or optimal processing scheme. Once developed, LP models can be used to perform sensitivity analysis, wherein the effect of varying feedstock value, product prices, quantities and specification can be considered.

The UOP LP system was developed over the years to apply this powerful mathematical method to the analysis of a grassroots refinery and expansion

projects. LP techniques are effectively used in: feedstock evaluation and selections, operations planning, financial planning for new facilities or expansion of existing ones, and development of planned turnaround maintenance. Combining the market data of product prices and demands with data describing technology and economic factors, the LP model can be used to evaluate many alternatives quickly and efficiently. Although the results are a linear representation of reality, they can give the planner a logical basis for a systematic approach to solving these problems.

To illustrate the mathematical relationships and the extent to which the refinery interactions are considered, a matrix representation of the linear equations is used to describe the refinery. In this arrangement, data relationships cascade from one activity to the next, much the same way material flows through the refinery. The model can consider the following general components of refinery profitability:

- Availability of raw materials
- Component blending relationships and recycle streams
- Process unit material balances
- Addition requirements for product quality improvements
- Utility consumptions and conversions (purchase vs. internal generation)
- Market demands for finished products.

The constraints or limitations on the model are contained in the rows of the matrix. The constraints considered in the refinery optimization are:

- Raw material purchase limits
- Unpooled utility limits to sale or purchase
- Product quality specifications
- Material balances on all streams in the refinery
- Capacity limits in process units
- Additive blending
- Utility balances (choice between purchase and internal generation)
- Product demands at market centers
- Physical and social requirements (e.g., emission limits)

Investment in onsite process equipment and related offsite facilities is handled in a manner that considers the non-linear relationship between capital cost and plant capacity. UOP's linear programming system has the ability to recurse on the capital cost to ensure that the capital charges used by the model are consistent with the calculated process unit capacity. The effect of physical and social policy requirements can be evaluated by placing additional constraints on the model and evaluating the results.

The output of the LP program is in the form of reports that allow management to evaluate the results in familiar terms including such terms as:

- Material balances including plant yields and product blends
- Processing schemes
- Utility balances
- Investment requirements
- Operating requirements
- Production costs

In addition, the LP allows the investigation of the sensitivity of the solution through a technique called post optimal analysis. This feature permits the quantified measurement of varying key parameters such as:

- Sales of selected products on various markets
- Capacity of particular process units
- Finished product qualities
- Prices of products and feedstocks

#### Conclusions

The total production costs for the JP-4 and JP-8 cases are tabulated in Table 75. Incorporating the feedstock cost, operating costs, capital charges, taxes and a 15% DCF rate, and assuming that all liquid products have equal value, the cost of total liquid fuel production in terms of \$/Bbl of shale oil feed are as follows:

<u>Case</u>	<u>\$/Bbl of Feed</u>
Max. JP-4	52.14
JP-4 + DF-2/DFM	53.42
Max. JP-8	52.68
JP-8 + DF-2/DFM	52.15

The difference in cost for the various cases is almost entirely due to the variations in capital cost, especially in the JP-4 + DF-2/DFM case which has the partial oxidation unit.

The product costs can be stated on a "per barrel of total liquid feed" basis and this is calculated by dividing production costs by the volume fraction yield of liquid fuel. Tabulated below are the results of the calculation for each case:

<u>Case</u>	<u>Total Liquid Product, BPSD</u>	<u>\$/Bbl of Liquid Products</u>
Max. JP-4	91,760	56.82
JP-4 + DF-2/DFM	90,826	58.82
Max. JP-8	89,591	58.80
JP-8 + DF-2/DFM	88,623	58.85

A more detailed analysis of these four cases is provided in the pro forma financial statements attached as Appendices B.1 to B.4 and in the Standard Optimization Reports attached as Appendices B.5 to B.8.

TABLE 50. SHALE OIL INSPECTION

Occidental Shale Oil

Feed Source	Desalted Shale Oil
Gravity, °API	22.9
Distillation (D-1160), °F	
IBP	376
50%	712
EP	953
% Over	87
Sulfur, wt-%	0.64
Nitrogen, wt-%	1.51
Pour Point, °F	+65
BS and W, vol-%	0.2
Conradson Carbon, wt-%	1.36
Carbon, wt-%	79.3
Hydrogen, wt-%	12.2
Oxygen, wt-%	0.65
Metals, wt-ppm	
Arsenic	27.5
Iron	23.0
Nickel	10.0
Vanadium	5.0
Ash, wt-%	0.014
Bromine Number	23.5

TABLE 51. OVERALL MATERIAL BALANCES

JP-4 and JP-8 Jet Fuel Cases

<u>Feed</u>	<u>Max. JP-4</u>			<u>JP-4 + DF-2/DFM</u>			<u>Max. JP-8</u>			<u>JP-8 + DF-2/DFM</u>		
	<u>Wt-%</u>	<u>Vol-%</u>	<u>BPSD</u>	<u>Wt-%</u>	<u>Vol-%</u>	<u>BPSD</u>	<u>Wt-%</u>	<u>Vol-%</u>	<u>BPSD</u>	<u>Wt-%</u>	<u>Vol-%</u>	<u>BPSD</u>
Shale Oil	100.00	100.00	100,000	100.00	100.00	100,000	100.00	100.00	100,000	100.00	100.00	100,000
<u>Liquid Products</u>												
Gasoline	-	-	-	-	-	-	7.21	8.85	8,849	2.92	3.52	3,521
Jet Fuel JP-4	78.23	91.76	91,760	46.24	53.96	53,955	-	-	-	-	-	-
Jet Fuel JP-8	-	-	-	-	-	-	70.92	80.74	80,742	48.50	55.22	55,219
Diesel (DF-2/DFM)	-	-	-	33.51	36.87	36,871	-	-	-	27.25	29.88	29,883
Total Liquid Products	78.23	91.76	91,760	79.75	90.83	90,826	78.13	89.59	89,591	78.67	88.62	88,623
<u>By-Products</u>												
Sulfur	0.61	-	-	0.61	-	-	0.61	-	-	0.61	-	-
Ammonia	1.91	-	-	1.91	-	-	1.92	-	-	1.91	-	-
Water (Net Make)	0.73	0.66	664	0.73	0.66	664	0.73	0.66	664	0.73	0.66	664
Total By-Products	3.25	-	-	3.25	-	-	3.26	-	-	3.25	-	-
<u>Streams Utilized as Fuel</u>												
Fuel Oil	13.78	14.62	14,622	9.88	10.48	10,481	8.43	8.95	8,947	13.50	14.32	14,319
Naphtha	-	-	-	-	-	-	5.57	7.69	7,687	-	-	-
Total Fuels	13.78	14.62	14,622	9.88	10.48	10,481	14.00	16.64	16,634	13.50	14.32	14,319
<u>Material Lost in Production</u>												
Total Losses	4.74	-	-	7.12	-	-	4.61	-	-	4.58	-	-

TABLE 52. OVERALL REACTOR YIELDS  
Low- and High-Pressure Hydrotreating

<u>Feed</u>	<u>JP-4 and JP-8 Cases</u>	
	<u>Wt-%</u>	<u>(SCFB) LV-%</u>
Shale Oil	100.00	100.00
Hydrogen (Chemical)	<u>2.36</u>	(1425)
Total	102.36	
 <u>Products</u>		
Water	0.73	
Ammonia	1.85	
Hydrogen Sulfide	0.68	
Propane and Lighter	0.76	
Butanes	0.32	0.51
Pentanes	0.53	0.78
Hexane +	<u>97.49</u>	<u>103.13</u>
Total	102.36	104.42

Estimated Properties of C<sub>6</sub>+

API Gravity	31.8
Sulfur, wt-%	0.003
Nitrogen, wt-%	0.09
C <sub>7</sub> Insolubles, wt-%	<0.05
Bromine Number	1.1
Distillation (D-1160), °F	
IBP	245
50%	646
EP	1034

TABLE 53. REACTOR YIELDS

HC Unibon				
	Maximum JP-4			
Feed	Wt-%	(SCFB) LV-%		
HT Shale Oil*	100.00	100.00		
Hydrogen (Chemical)	<u>1.57</u>	(885)		
Total	101.57			
Products				
Ammonia	0.11			
Propane and Lighter	3.53			
Butanes	4.85			
Light Naphtha (C <sub>5</sub> /C <sub>6</sub> )	11.25	14.49		
Heavy Naphtha (C <sub>7</sub> -300°F)	6.98	7.83		
Kerosine (300-520°F)	<u>74.85</u>	<u>79.84</u>		
Total	101.57	102.16		
Estimated Properties				
	Charge	C <sub>5</sub> /C <sub>6</sub>	Naphtha	Kerosine
Dist. Range, °F			C <sub>7</sub> -300	300-520
API Gravity	31.8	81.6	54.3	45.0
Sulfur, wt-ppm	30	3	3	3
Nitrogen, wt-ppm	900	< 1	< 1	3
Distillation (D-1160), °F				
IBP	245	90	200	300
50%	646	130	240	404
EP	1034	180	285	520
RVP, psi	-	12.9	-	-
P/N/A, vol-%	-	83/15/2	44/49/7	-
RON Clear	-	75	59	-
RON + 3 cc TEL/gal	-	93	78	-
Flash Point, °F	-	-	-	100
Aromatics, vol-%	-	-	-	9.0
Freeze Point, °F	-	-	-	-58
Naphthalenes, wt-%	-	-	-	0.4
Smoke Point, mm	-	-	-	27

\* Total hydrotreater, high-pressure separator liquid.

TABLE 54. REACTOR YIELDS

HC Unibon

<u>Feed</u>	<u>JP-4 + DF-2/DFM</u>	
	<u>Wt-%</u>	(SCFB) <u>LV-%</u>
HT Shale Oil*	100.00	100.00
Hydrogen (Chemical)	<u>1.43</u>	(803)
Total	101.43	
<u>Products</u>		
Ammonia	0.11	
Propane and Lighter	2.02	
Butanes	2.38	
Light Naphtha (C <sub>5</sub> /C <sub>6</sub> )	5.21	6.76
Heavy Naphtha (C <sub>7</sub> -300°F)	3.09	3.47
Kerosine (300-520°F)	48.03	51.24
Diesel (520-700°F)	<u>40.59</u>	<u>41.67</u>
Total	101.43	103.14

Estimated Properties

	<u>Charge</u>	<u>C<sub>5</sub>/C<sub>6</sub></u>	<u>Naphtha</u>	<u>Kerosine</u>	<u>Diesel</u>
Dist. Range, °F			C <sub>7</sub> -300	300-520	520-700
API Gravity	31.8	82.3	54.3	45.0	38.4
Sulfur, wt-ppm	30	3	3	3	3
Nitrogen, wt-ppm	900	< 1	< 1	3	3
Distillation (D-1160), °F					
IBP	245	90	200	300	520
50%	646	130	240	404	605
EP	1034	180	285	520	700
RVP, psi	-	12.9	-	-	-
P/N/A, vol-%	-	83/15/2	44/49/7	-	-
RON Clear	-	75	59	-	-
RON + 3 cc TEL/gal	-	93	78	-	-
Flash Point, °F	-	-	-	100	268
Aromatics, vol-%	-	-	-	9.0	-
Freeze Point, °F	-	-	-	-50	-
Naphthalenes, wt-%	-	-	-	0.4	-
Smoke Point, mm	-	-	-	27	-
Pour Point, °F	-	-	-	-	0
Cetane Number	-	-	-	-	56
Cloud Point, °F	-	-	-	-	5
Aniline Point, °F	-	-	-	-	198
Viscosity, cSt at 100°F	-	-	-	-	4.4

\* Total hydrotreater, high-pressure separator liquid.

TABLE 55. REACTOR YIELDS

<u>HC Unibon</u>				
	<u>Maximum JP-8</u>			
<u>Feed</u>	<u>Wt-%</u>	<u>(SCFB)</u> <u>LV-%</u>		
HT Shale Oil*	100.00	100.00		
Hydrogen (Chemical)	<u>1.55</u>	(874)		
Total	101.55			
<u>Products</u>				
Ammonia	0.11			
Propane and Lighter	3.13			
Butanes	4.25			
Light Naphtha (C <sub>5</sub> /C <sub>6</sub> )	9.78	12.60		
Heavy Naphtha (C <sub>7</sub> -300°F)	5.99	6.73		
Kerosine (300-550°F)	<u>78.29</u>	<u>83.18</u>		
Total	101.55	102.51		
<u>Estimated Properties</u>				
	<u>Charge</u>	<u>C<sub>5</sub>/C<sub>6</sub></u>	<u>Naphtha</u>	<u>Kerosine</u>
Dist. Range, °F			C <sub>7</sub> -300	300-550
API Gravity	31.8	81.7	54.3	44.3
Sulfur, wt-ppm	30	3	3	3
Nitrogen, wt-ppm	900	< 1	< 1	3
Distillation (D-1160), °F				
IBP	245	90	200	300
50%	646	130	240	419
EP	1034	180	285	550
RVP, psi	-	12.9	-	-
P/N/A, vol-%	-	83/15/2	44/49/7	-
RON Clear	-	75	59	-
RON + 3 cc TEL/gal	-	93	78	-
Flash Point, °F	-	-	-	100
Aromatics, vol-%	-	-	-	10
Freeze Point, °F	-	-	-	-58
Naphthalenes, wt-%	-	-	-	1.5
Smoke Point, mm	-	-	-	26

\* Total hydrotreater, high-pressure separator liquid.

TABLE 56. REACTOR YIELDS

HC Unibon

<u>Feed</u>	<u>JP-8 + DF-2/DFM</u>	
	<u>Wt-%</u>	(SCFB) <u>LV-%</u>
HT Shale Oil*	100.00	100.00
Hydrogen (Chemical)	1.43	(803)
Total	101.43	
<u>Products</u>		
Ammonia	0.11	
Propane and Lighter	2.02	
Butanes	2.38	
Light Naphtha (C <sub>5</sub> /C <sub>6</sub> )	5.21	6.76
Heavy Naphtha (C <sub>7</sub> -300°F)	3.09	3.47
Kerosine (300-550°F)	56.74	60.29
Diesel (550-700°F)	31.88	32.62
Total	101.43	103.14

Estimated Properties

	<u>Charge</u>	<u>C<sub>5</sub>/C<sub>6</sub></u>	<u>Naphtha</u>	<u>Kerosine</u>	<u>Diesel</u>
Dist. Range, °F			C <sub>7</sub> -300	300-550	550-700
API Gravity	31.8	82.3	54.3	44.3	37.8
Sulfur, wt-ppm	30	3	3	3	3
Nitrogen, wt-ppm	900	< 1	< 1	3	3
Distillation (D-1160), °F					
IBP	245	90	200	300	550
50%	646	130	240	419	620
EP	1034	180	285	550	700
RVP, psi	-	12.9	-	-	-
P/N/A, vol-%	-	83/15/2	44/49/7	-	-
RON Clear	-	75	59	-	-
RON + 3 cc TEL/gal	-	93	78	-	-
Flash Point, °F	-	-	-	100	288
Aromatics, vol-%	-	-	-	10	-
Freeze Point, °F	-	-	-	-58	-
Naphthalenes, wt-%	-	-	-	1.5	-
Smoke Point, mm	-	-	-	26	-
Pour Point, °F	-	-	-	-	0
Cetane Number	-	-	-	-	56
Cloud Point, °F	-	-	-	-	5
Aniline Point, °F	-	-	-	-	200
Viscosity, cSt at 100°F	-	-	-	-	4.5

\* Total hydrotreater, high-pressure separator liquid.

TABLE 57. REACTOR YIELDS

Naphtha Hydrotreating UnitMax. JP-8 and JP-8 + DF-2/DFM

<u>Feed</u>	<u>Wt-%</u>	(SCFB) <u>LV-%</u>
Hydrocracked Naphtha (C <sub>7</sub> -300°F)	100.00	100.00
Hydrogen (Chemical)	<u>0.03</u>	(16)
Total	100.03	

Products

Hydrogen Sulfide	0.02	
Propane and Lighter	0.02	
Butanes	0.01	
Pentanes	0.02	
Hexane +	<u>99.96</u>	<u>100.01</u>
Total	100.03	100.01

Properties of Hexane +

API Gravity	54.4
Sulfur, wt-%	0.00005
Hydrocarbon Type, vol-%	
P	44
N	49
A	7

TABLE 58. REACTOR YIELDS

<u>UOP Platforming Unit</u>				
<u>Feed</u>	<u>Maximum JP-8</u>		<u>JP-8 + DF-2/DFM</u>	
	<u>Wt-%</u>	<u>(SCFB) LV-%</u>	<u>Wt-%</u>	<u>(SCFB) LV-%</u>
Hydrotreated Naphtha (C <sub>7</sub> -300°F)	100.00	100.00	100.00	100.00
<u>Products</u>				
Hydrogen	2.65	(1332)	2.54	(1276)
Propane and Lighter	7.00		6.26	
Butanes	3.95	5.23	3.53	4.67
C <sub>5</sub> + Platformate	<u>86.40</u>	<u>79.97</u>	<u>87.67</u>	<u>81.85</u>
Total	100.00		100.00	
<u>Properties of C<sub>5</sub>+ Platformate</u>				
API Gravity	40.4		41.9	
RON Clear	100.0		98.0	
RON + 3 cc TEL/USG	105.2		103.7	
MON Clear	88.6		87.0	
MON + 3 cc TEL/USG	92.7		91.5	
RVP, psi	4.0		3.9	

TABLE 59. ESTIMATED YIELDS

Hydrogen Plant -- Steam Reforming

Feed to H <sub>2</sub> Plant	JP-4 Case					JP-4 + DF-2/DFM Case				
	BPSD	Sp.Gr.	MW	MMSCFD	Wt-%	BPSD	Sp.Gr.	MW	MMSCFD	Wt-%
Treated Fuel Gas	652	0.6645	24.3	45.6	95.1	-	-	18.2	35.1	100.0
Light Naphtha			-	-	4.9			-	-	-
Total Feed					100.0					100.0
<u>Products</u>										
Hydrogen				247.5	42.7				141.4	44.5
CH <sub>4</sub>				7.6	10.5				4.4	11.0
Total H <sub>2</sub> (97% Purity)				255.1	53.2				145.8	55.5
Process Loss					46.8					44.5
Total Products					100.0					100.0

Estimated Process Units H<sub>2</sub> Requirements

Unit	H <sub>2</sub> MMSCFD	H <sub>2</sub> MMSCFD
Low- and High-Pressure Hydrotreater	154.3	154.3
Hydrocracker (HC Unibon)	93.2	82.9
Total Hydrogen Required	247.5	237.2
Hydrogen Required from Partial Oxidation	0	95.8

TABLE 60. ESTIMATED YIELDS

Hydrogen Plant -- Steam Reforming

	JP-8 Case				JP-8 + DF-2/DFM Case					
	BPSD	Sp.Gr.	MW	MMSCFD	Wt-%	BPSD	Sp.Gr.	MW	MMSCFD	Wt-%
Feed to H <sub>2</sub> Plant										
Treated Fuel Gas			22.3	43.7	83.9			17.8	35.4	55.8
Platformer Gas			8.7	10.8	8.1			6.7	4.3	2.6
Light Naphtha	1060	0.6643	-	-	8.0	5345	0.6625	-	-	41.6
Total Feed					100.0					100.0
Products										
Hydrogen				252.5	43.7				240.3	42.9
CH <sub>4</sub>				7.8	10.8				7.4	10.5
Total H <sub>2</sub> (97% Purity)				260.3	54.5				247.7	53.4
Process Loss					45.5					46.6
Total Products					100.0					100.0

Estimated Process Units H<sub>2</sub> Requirements

<u>Unit</u>	<u>H<sub>2</sub></u> <u>MMSCFD</u>	<u>H<sub>2</sub></u> <u>MMSCFD</u>
Low- and High-Pressure Hydrotreater	154.3	154.3
Hydrocracker (HC Unibon)	98.0	85.8
Naphtha Hydrotreater	0.2	0.2
Total Hydrogen Required	252.5	240.3

TABLE 61. ESTIMATED YIELDS

Hydrogen Plant -- Partial Oxidation

<u>Feed to H<sub>2</sub> Plant</u>	<u>JP-4 + DF-2/DFM Case</u>			
	<u>BPSD</u>	<u>Sp.Gr.</u>	<u>MMSCFD</u>	<u>Wt-%</u>
HT Shale Oil	6906	0.8640		100.0
<u>Products</u>				
Hydrogen			95.8	24.4
CH <sub>4</sub>			<u>3.0</u>	<u>6.0</u>
Total H <sub>2</sub> (97% Purity)			98.8	30.4
Process Loss				69.6
Total Products				100.0

TABLE 62. UTILITY CONSUMPTION

Maximum JP-4

	Power, kWh	Steam, M lb/hr			BFW and Condensate, M lb/hr	Cooling Water, gpm	Fuel Fired, MM btu/hr	Cold Treated Water, M lb/hr
		HP	MP	LP				
Feed Preparation	450	-	-	-	-	-	-	-
LP Hydrotreating (RCD Unibon)	7,945	-80.2	-	-	+80.2	112	91	39.4
HP Hydrotreating	5,436	-67.7	-	-	+67.7	-	207	135.2
HC Unibon - Hydrocracking	27,797	-29.5	-	+12.1	-14.4	2597	677	35.8
Hydrogen Plant (Steam Reforming)	8,045	+177.4	-	-	-576.4	472	1963	-
Fuel Gas Treating	185	-	-7.5	-42.4	+49.9	2455	-	-
Sulfur Plant	100	-1.0	+34.5	+44.9	-83.0	-	-	-
Sour Water Treating	351	-	-213.7	-	+213.7	4141	-	-
Fractionation	566	-	-	-38.2	+38.2	733	74	-
Fuel Oil Stabilizer	105	-	-	-	-	214	31	-
TOTAL	50,980	-1.0	-186.7	-23.6	-224.1	10,724	3043	210.4

## NOTES:

1. Negative sign indicates consumption
2. Positive sign indicates production
3. Maximum air cooling
4. Fuel fired heating based on net heating value.

TABLE 63. UTILITY CONSUMPTION

JP-4 + DF-2/DFM

	Power, kWh	Steam, M lb/hr			BFW and Condensate, M lb/hr	Cooling Water, gpm	Fuel Fired, MM btu/hr	Cold Treated Water, M lb/hr
		HP	MP	LP				
Feed Preparation	450	-	-	-	-	-	-	-
LP Hydrotreating (RCD Unibon)	7,945	-80.2	-	-	+80.2	112	91	39.4
HP Hydrotreating	5,436	-67.7	-	-	+67.7	-	207	135.2
HC Unibon - Hydrocracking	23,171	-	+70.4	+44.3	-148.2	1661	653	34.7
Hydrogen Plant (Steam Reforming)	4,661	+97.5	-	-	-322.9	282	1110	-
Hydrogen Plant (Partial Oxidation)	27,384	+186.1	-	-	-166.2	21,657	187	-
Fuel Gas Treating	185	-	-7.5	-42.4	+49.9	2454	-	-
Sulfur Plant	100	-1.0	+34.5	+44.8	-83.0	-	-	-
Sour Water Treating	349	-	-212.4	-	+212.4	4126	-	-
Fractionation	262	-	-	-17.9	+17.9	339	34	-
Fuel Oil Stabilizer	125	-	-	-	-	254	37	-
TOTAL	70,068	+134.7	-115.0	+28.8	-292.2	30,885	2319	209.3

## NOTES:

1. Negative sign indicates consumption
2. Positive sign indicates production
3. Maximum air cooling
4. Fuel fired heating based on net heating value.

TABLE 64. UTILITY CONSUMPTION

Maximum JP-8

	Power, kWh	Steam, M lb/hr			BFW and Condensate, M lb/hr	Cooling Water, gpm	Fuel Fired, MM btu/hr	Cold Treated Water, M lb/hr
		HP	MP	LP				
Feed Preparation	450	-	-	-	-	-	-	-
LP Hydrotreating (RCD Unibon)	7,945	-80.2	-	-	+80.2	112	91	39.4
HP Hydrotreating	5,436	-67.7	-	-	+67.7	-	207	135.2
HC Unibon - Hydrocracking	29,559	-31.3	-	+12.9	-15.3	2761	720	38.1
Naphtha Hydrotreating	191	-	-	-	-	53	5	-
Platforming	659	+16.3	-0.2	-	-17.4	382	87	-
Hydrogen Plant (Steam Reforming)	8,142	+185.1	-	-	-595.1	468	2016	-
Fuel Gas Treating	185	-	-7.5	-42.4	+49.9	2454	-	-
Sulfur Plant	100	-1.0	+34.5	+44.8	-83.0	-	-	-
Sour Water Treating	358	-	-218.5	-	+218.5	4188	-	-
Fractionation	531	-	-	-37.0	+37.0	760	68	-
Fuel Oil Stabilizer	64	-	-	-	-	131	19	-
TOTAL	53,620	+21.2	-191.7	-21.7	-257.5	11,309	3213	212.7

## NOTES:

1. Negative sign indicates consumption
2. Positive sign indicates production
3. Maximum air cooling
4. Fuel fired heating based on net heating value.

TABLE 65. UTILITY CONSUMPTION

JP-8 + DF-2/DFM

	Power, kWh	Steam, M lb/hr		BFW and Condensate, M lb/hr	Cooling Water, gpm	Fuel Fired, MM btu/hr	Cold Treated Water, M lb/hr
		HP	MP	LP			
Feed Preparation	450	-	-	-	-	-	-
LP Hydrotreating (RCD Unibon)	7,945	-80.2	-	-	112	91	39.4
HP Hydrotreating	5,436	-67.7	-	-	-	207	135.2
HC Unibon - Hydrocracking	23,991	-	+72.8	+45.9	1720	676	35.9
Naphtha Hydrotreating	85	-	-	-	24	2	-
Platforming	279	+7.2	-0.1	-	160	37	-
Hydrogen Plant (Steam Reforming)	7,021	+221.8	-	-	295	2057	-
Fuel Gas Treating	185	-	-7.5	-42.4	2454	-	-
Sulfur Plant	100	-1.0	+34.5	+44.8	-	-	-
Sour Water Treating	352	-	-214.8	-	4150	-	-
Fractionation	274	-	-	-19.3	393	35	-
Fuel Oil Stabilizer	103	-	-	-	209	31	-
TOTAL	46,221	+80.1	-115.1	+29.0	9517	3136	210.5

## NOTES:

1. Negative sign indicates consumption
2. Positive sign indicates production
3. Maximum air cooling
4. Fuel fired heating based on net heating value.

TABLE 66. PROCESS UNITS CAPACITIES AND CAPITAL INVESTMENTS

	Max. JP-4		JP-4 + DF-2/DFM		Max. JP-8		JP-8 + DF-2/DFM	
	(S Ton/SD) BPSD	MM Dollars	(S Ton/SD) BPSD	MM Dollars	(S Ton/SD) BPSD	MM Dollars	(S Ton/SD) BPSD	MM Dollars
Feed Preparation	100,000	9	100,000	9	100,000	9	100,000	9
LP Hydrotreating (RCD Unibon)	100,000	59	100,000	59	100,000	59	100,000	59
HP Hydrotreating	102,920	97	102,920	97	102,920	97	102,920	97
Hydrocracking (HC Unibon)	94,000	169	91,095	165	99,965	176	94,320	169
Fractionation	-	6	-	4	-	7	-	5
Fuel Gas Treating	-	4	-	4	-	4	-	4
Sulfur Plant	(97.5)	6	(97.5)	6	(97.5)	6	(97.5)	6
Hydrogen Plant (Steam Reforming)	(819.2)	125	(468.2)	79	(835.9)	127	(795.4)	122
Hydrogen Plant (Partial Oxidation)	-	-	(317.1)	114	-	-	-	-
Naphtha Hydrotreating	-	-	-	-	6,485	4	2,875	2
Platforming	-	-	-	-	6,485	11	2,875	6
Sour Water Treating	19,480	10	19,365	10	19,920	10	19,580	10
Fuel Oil Stabilizer	15,360	3	18,265	3	9,400	2	15,040	3
Common Facilities	-	11	-	11	-	11	-	11
TOTAL PROCESS INVESTMENT		499		561		523		503

Note: Capital Investment as of First Quarter 1981.

TABLE 67. PRODUCT QUALITIES

## JP-4 and JP-8 Jet Fuels

	JP-4 Military Specs.	JP-4		JP-4 + DF-2/DFM		JP-8		JP-8 + DF-2/DFM	
		Max.	Case	Case	Case	Military Specs.	Case	Case	Case
API Gravity,	45-57	49.6		48.7		37-51		44.3	44.3
Aromatics, vol-%	25 (max)	7.9		8.2		25 (max)		10.0	10.0
Flash Point, °F	-	-		-		100 (min)		> 100	> 100
Freeze Point, °F	-72 (max)	< -72		< -72		-58 (max)		< -58	< -58
Smoke Point, mm	20 (min)	> 20		> 20		20 (min)		26	26
Sulfur, wt-%	0.40 (max)	0.0003		0.0003		0.40 (max)		0.0003	0.0003
Naphthalenes, vol-%	-	-		-		3.0 (max)		1.5	1.5
Olefins, vol-%	5.0 (max)	nil		nil		5.0 (max)		nil	nil
Distillation, °F									
IBP	Report	108		111		Report		300	300
10%	Report	179		200		401 (max)		337	337
20%	293 (max)	250		270		Report		361	361
50%	374 (max)	374		381		Report		419	419
90%	473 (max)	473		479		Report		512	512
EP	518 (max)	518		520		572 (max)		550	550

TABLE 68. DF-2 and DFM DIESEL FUELS

	<u>DF-2 Diesel Fuel (Oconus) Specs.</u>	<u>Diesel Fuel Marine Specs.</u>	<u>JP-4 + DF-2/DFM Case</u>	<u>JP-8 + DF-2/DFM Case</u>
Gravity, °API	32.9-41.0	Report	38.4	37.8
Flash Point, °F	133 (Min.)	140 (Min.)	268	288
Cloud Point, °F	9 (Max.)	30 (Max.)	5	5
Pour Point, °F	0 (Max.)	20 (Max.)	0	0
Sulfur, wt-%	0.7 (Max.)	1.0 (Max.)	0.0003	0.0003
Cetane Number	45 (Min.)	-	56	56
Aniline Point, °F	-	Report	198	200
Viscosity: cSt at 100°F	1.8-9.5	1.8-4.5	4.4	4.5
Distillation, °F				
50%	Report	-	605	620
90%	675 (Max.)	675 (Max.)	673	675
EP	700 (Max.)	725 (Max.)	700	700

TABLE 69. GASOLINE BLENDS AND QUALITIES

Special Grade -- Unleaded

<u>Gasoline Component</u>	<u>Max. JP-8 Case Gasoline</u>		<u>JP-8 + Diesel Gasoline</u>	
	<u>vol-%</u>	<u>BPSD</u>	<u>vol-%</u>	<u>BPSD</u>
Platformate	58.1	5,139	66.4	2,337
Heavy Naphtha	-	-	7.9	280
Light Gasoline	31.4	2,776	12.9	454
Mixed Butanes	10.5	934	12.8	450
TOTAL	100.0	8,849	100.0	3,521

<u>Properties of Gasoline</u>	<u>Military Specs.</u>	<u>Max. JP-8 Gasoline</u>	<u>JP-8 + Diesel Gasoline</u>
API Gravity	-	57.9	54.5
RON Clear	92.0 (Min.)	92.0	92.0
MON Clear	82.0 (Min.)	84.3	83.7
R+M/2	87.0 (Min.)	88.1	87.9
RVP, psi	13.5 (Max.)	13.5	13.5
Sulfur, wt-%	0.10 (Max.)	0.0003	0.0003
Aromatics, vol-%	55.0 (Max.)	42.8	46.3
Distillation (D-1160), °F			
IBP	-	53	84
10%	131 (Max.)	105	129
30%	-	145	171
50%	171 (Min.)-235 (Max.)	183	213
70%	-	245	249
90%	365 (Max.)	292	284
EP	437 (Max.)	342	335

TABLE 70. MAX. JP-4 CASE -- ESTIMATED OPERATING COST

Basis: 100,000 BPSD at 90% Operating Efficiency

Direct Operating Cost

A. <u>Refinery Labor</u>	<u>MM\$/Yr.</u>	<u>MM\$/Yr.</u>
<u>Direct Labor</u>		
76 operators	2.67	
28 helpers	<u>0.85</u>	
Total Direct Labor	3.52	
<u>Supervision</u>		
25% of Direct Labor	<u>0.88</u>	
Total Operating Labor	4.40	
<u>Overhead</u>		
100% of Operating Labor	<u>4.40</u>	
Total Labor	8.80	8.80
 B. <u>Maintenance</u>		
Maintenance Allowance at 3% of Plant Investment		22.92
 C. <u>Utilities</u>		
Power: 50,981 kWh at \$0.045/kWh	18.09	
600 lb Steam: 211.3 M lb/hr at \$0.68/M lb (cost)	1.13	
BF Water: 224.1 M lb/hr at \$0.50/M lb	0.88	
Cold Treated Water: 233.8 M lb/hr at \$0.07/M lb	0.13	
Cooling Water: 643.4 M gal/hr at \$0.03/M gal	<u>0.15</u>	
Total Utilities	20.38	20.38
 D. <u>Catalyst Replacement, Solvents and Chemicals</u>		
First-Stage Hydrotreating (RCD Unibon)	3.76	
Second-Stage Hydrotreating	1.41	
Hydrocracking (HC Unibon)	2.26	
Hydrogen Plant	<u>1.35</u>	
Total Catalysts, Solvents and Chemicals	8.78	<u>8.78</u>
Total Direct Operating Cost		60.88

TABLE 70. MAX. JP-4 CASE -- ESTIMATED OPERATING COST (Cont'd)

	<u>MM\$/Yr.</u>
<u>Indirect Operating Cost</u>	
<u>Local Taxes</u>	
Local Taxes Allowance at 1% of Plant Investment, Catalyst and Working Capital	8.83
<u>Insurance</u>	
Insurance Allowance at 1/2% of Plant Investment, Catalyst and Working Capital	<u>4.41</u>
Total Indirect Operating Cost	<u>13.24</u>
Total Operating Cost	74.12

TABLE 71. JP-4 + DIESEL CASE -- ESTIMATED OPERATING COST

Basis: 100,000 BPSD at 90% Operating Efficiency

Direct Operating Cost

A. <u>Refinery Labor</u>	<u>MM\$/Yr.</u>	<u>MM\$/Yr.</u>
<u>Direct Labor</u>		
86 operators	3.00	
32 helpers	<u>0.99</u>	
Total Direct Labor	3.99	
<u>Supervision</u>		
25% of Direct Labor	<u>1.00</u>	
Total Operating Labor	4.99	
<u>Overhead</u>		
100% of Operating Labor	<u>4.99</u>	
Total Labor	9.98	9.98
B. <u>Maintenance</u>		
Maintenance Allowance at 3% of Plant Investment		25.62
C. <u>Utilities</u>		
Power: 70,069 kWh at \$0.045/kWh	24.86	
600 lb Steam: None	-	
BF Water: 292.1 M lb/hr at \$0.50/M lb	1.15	
Cold Treated Water: 232.5 M lb/hr at \$0.07/M lb	0.13	
Cooling Water: 1853.1 M gal/hr at \$0.03/M gal	<u>0.44</u>	
Total Utilities	26.58	26.58
D. <u>Catalyst Replacement, Solvents and Chemicals</u>		
First-Stage Hydrotreating (RCD Unibon)	3.76	
Second-Stage Hydrotreating	1.41	
Hydrocracking (HC Unibon)	1.73	
Hydrogen Plant	<u>1.21</u>	
Total Catalysts, Solvents and Chemicals	8.11	<u>8.11</u>
Total Direct Operating Cost		70.29

TABLE 71. JP-4 + DIESEL CASE -- ESTIMATED OPERATING COST (Cont'd)

MMS/Yr.

Indirect Operating Cost

Local Taxes

Local Taxes Allowance at 1%  
of Plant Investment, Catalyst  
and Working Capital

9.70

Insurance

Insurance Allowance at 1/2%  
of Plant Investment, Catalyst  
and Working Capital

4.85

Total Indirect Operating Cost

14.55

Total Operating Cost

84.84

TABLE 72. MAX. JP-8 CASE -- ESTIMATED OPERATING COST

Basis: 100,000 BPSD at 90% Operating Efficiency

Direct Operating Cost

A. <u>Refinery Labor</u>	<u>MM\$/Yr.</u>	<u>MM\$/Yr.</u>
<u>Direct Labor</u>		
88 operators	3.07	
32 helpers	<u>0.99</u>	
Total Direct Labor	4.06	
<u>Supervision</u>		
25% of Direct Labor	<u>1.02</u>	
Total Operating Labor	5.08	
<u>Overhead</u>		
100% of Operating Labor	<u>5.08</u>	
Total Labor	10.16	10.16
B. <u>Maintenance</u>		
Maintenance Allowance at 3% of Plant Investment		23.97
C. <u>Utilities</u>		
Power: 53,622 kWh at \$0.045/kWh	19.02	
600 lb Steam: 192.2 M lb/hr at \$0.68/M lb (cost)	1.03	
BF Water: 257.5 M lb/hr at \$0.50/M lb	1.02	
Cold Treated Water: 235.1 M lb/hr at \$0.07/M lb	0.13	
Cooling Water: 678.6 M gal/hr at \$0.03/M gal	<u>0.16</u>	
Total Utilities	21.36	21.36
D. <u>Catalyst Replacement, Solvents and Chemicals</u>		
First-Stage Hydrotreating (RCD Unibon)	3.76	
Second-Stage Hydrotreating	1.41	
Hydrocracking (HC Unibon)	2.30	
Hydrogen Plant	1.38	
Naphtha Hydrotreating and Platformer	<u>0.13</u>	
Total Catalysts, Solvents and Chemicals	8.98	<u>8.98</u>
Total Direct Operating Cost		64.47

TABLE 72. MAX. JP-8 CASE -- ESTIMATED OPERATING COST (Cont'd)

	<u>MM\$/Yr.</u>
<u>Indirect Operating Cost</u>	
<u>Local Taxes</u>	
Local Taxes Allowance at 1% of Plant Investment, Catalyst and Working Capital	9.20
<u>Insurance</u>	
Insurance Allowance at 1/2% of Plant Investment, Catalyst and Working Capital	<u>4.60</u>
Total Indirect Operating Cost	<u>13.80</u>
Total Operating Cost	78.27

TABLE 73. JP-8 + DIESEL CASE -- ESTIMATED OPERATING COST

Basis: 100,000 BPSD at 90% Operating Efficiency

Direct Operating Cost

A. <u>Refinery Labor</u>	<u>MM\$/Yr.</u>	<u>MM\$/Yr.</u>
<u>Direct Labor</u>		
88 operators	3.07	
32 helpers	<u>0.99</u>	
Total Direct Labor	4.06	
<u>Supervision</u>		
25% of Direct Labor	<u>1.02</u>	
Total Operating Labor	5.08	
<u>Overhead</u>		
100% of Operating Labor	<u>5.08</u>	
Total Labor	10.16	10.16
B. <u>Maintenance</u>		
Maintenance Allowance at 3% of Plant Investment		23.10
C. <u>Utilities</u>		
Power: 46,222 kWh at \$0.045/kWh	16.40	
600 lb Steam: 34.9 M lb/hr at \$0.68/M lb (cost)	0.19	
BF Water: 454.8 M lb/hr at \$0.50/M lb	1.79	
Cold Treated Water: 235.1 M lb/hr at \$0.07/M lb	0.13	
Cooling Water: 571.0 M gal/hr at \$0.03/M gal	<u>0.13</u>	
Total Utilities	18.64	18.64
D. <u>Catalyst Replacement, Solvents and Chemicals</u>		
First-Stage Hydrotreating (RCD Unibon)	3.76	
Second-Stage Hydrotreating	1.41	
Hydrocracking (HC Unibon)	1.79	
Hydrogen Plant	1.36	
Naphtha Hydrotreater and Platformer	<u>0.05</u>	
Total Catalysts, Solvents and Chemicals	8.37	<u>8.37</u>
Total Direct Operating Cost		60.27

TABLE 73. JP-8 + DIESEL CASE -- ESTIMATED OPERATING COST (Cont'd)

MM\$/Yr.Indirect Operating CostLocal Taxes

Local Taxes Allowance at 1%  
of Plant Investment, Catalyst  
and Working Capital

8.86Insurance

Insurance Allowance at 1/2%  
of Plant Investment, Catalyst  
and Working Capital

4.43

Total Indirect Operating Cost

13.29

Total Operating Cost

73.56

TABLE 74. CAPITAL INVESTMENT SUMMARY

(Millions of Dollars)

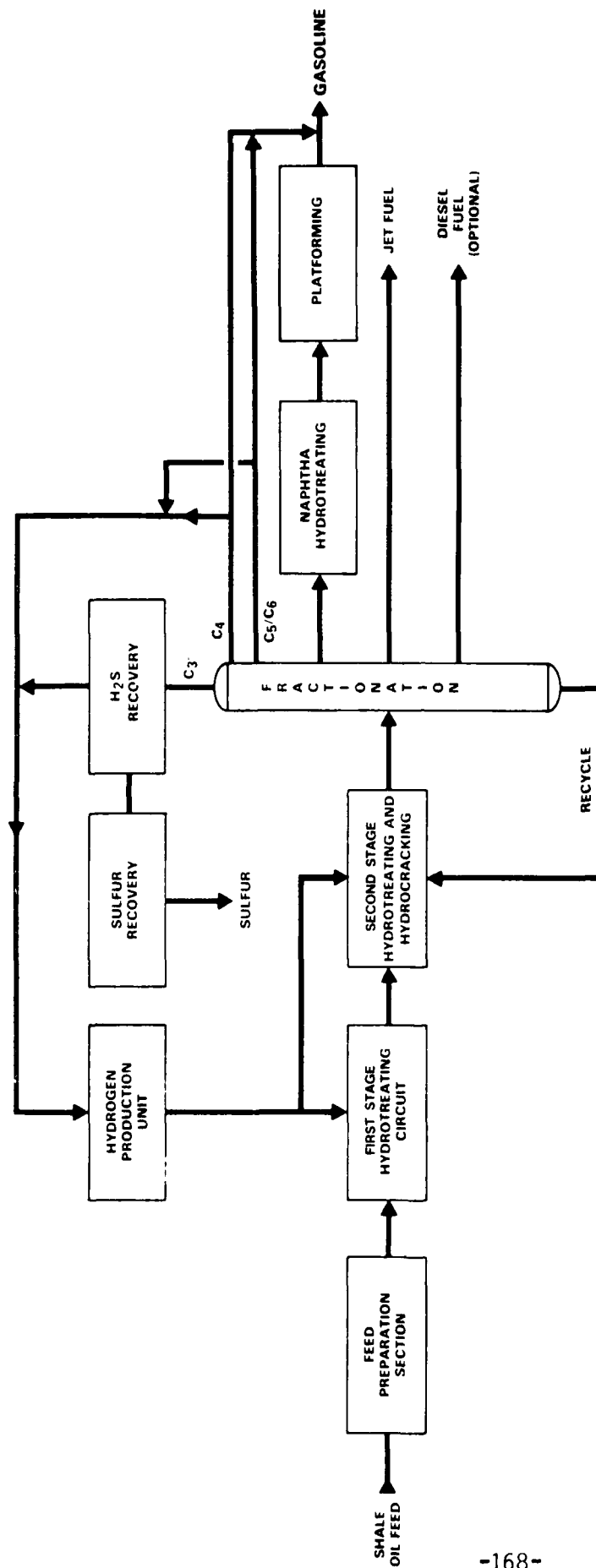
100,000 BPSD Refinery

	<u>Max. JP-4</u>	<u>JP-4 + Diesel</u>	<u>Max. JP-8</u>	<u>JP-8 + Diesel</u>
Process Units Erected Cost	499	561	523	503
Allowance for Offsites	265	293	276	267
Allowance for Fully Paid Royalties and Know-How Fees	<u>20</u>	<u>20</u>	<u>20</u>	<u>20</u>
TOTAL DEPRECIABLE INVESTMENT	784	874	819	790
Initial Catalyst Inventory	25	22	27	23
Working Capital Allowance	<u>93</u>	<u>93</u>	<u>93</u>	<u>92</u>
TOTAL CAPITAL INVESTMENT	902	989	939	905

TABLE 75. COST OF PRODUCTION BREAKDOWN

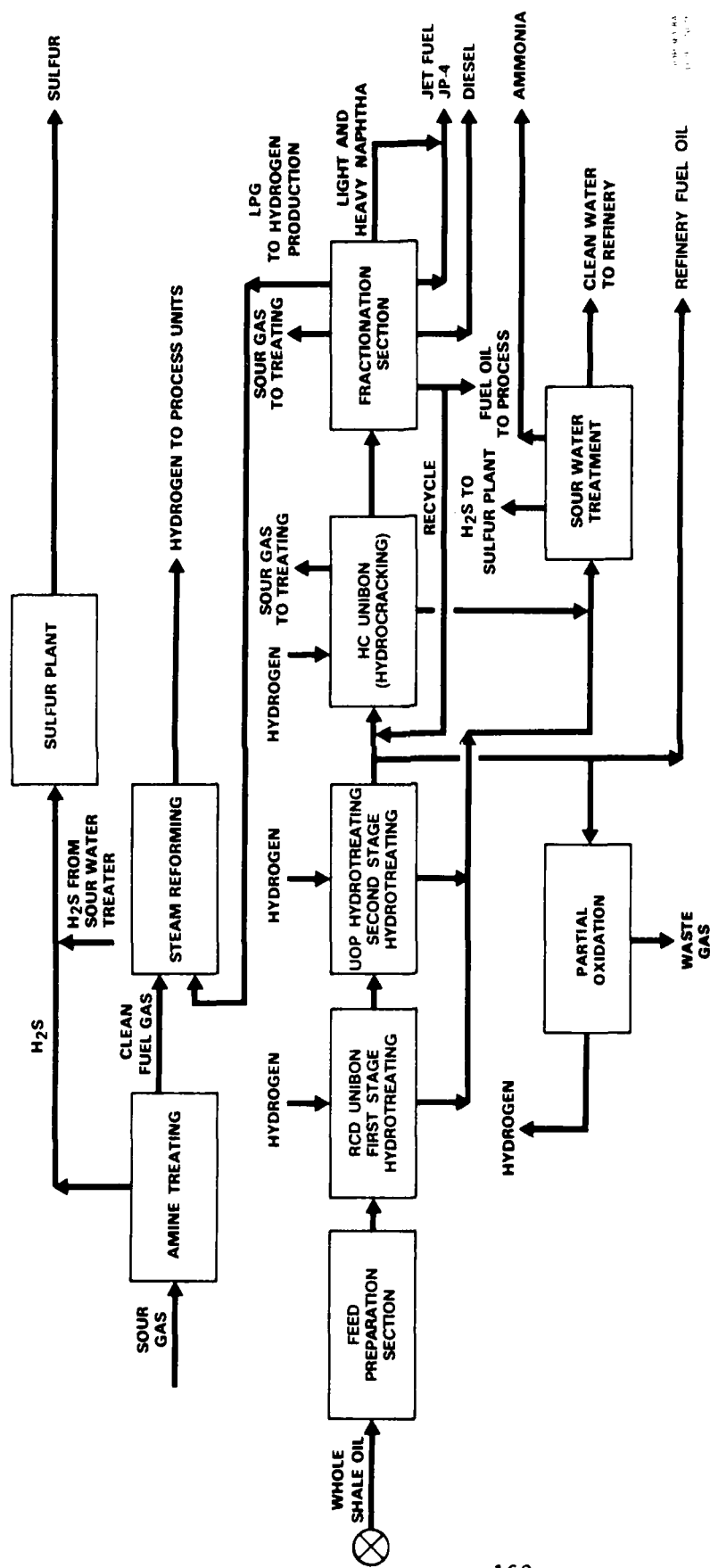
100,000 BPSD Charge Rate

	Max. <u>JP-4</u>	JP-4 + <u>DF-2/DFM</u>	Max. <u>JP-8</u>	JP-8 + <u>DF-2/DFM</u>
Operating Cost, \$/Bbl of Feed	2.26	2.58	2.38	2.24
Cost of Feed, \$/Bbl	40.00	40.00	40.00	40.00
Capital Charges for 15% DCF Return, \$/Bbl of Feed	9.88	10.84	10.30	9.91
Total Cost of Production, \$/Bbl of Feed	<u>52.14</u>	<u>53.42</u>	<u>52.68</u>	<u>52.15</u>
Total Cost of Liquid Products, \$/Bbl	56.82	58.82	58.80	58.85



UOP 525-90  
UOP 710-15

**FIGURE 31**  
**UOP SHALE OIL TO FUELS**  
**OVERALL BLOCK FLOW DIAGRAM**



**FIGURE 32**  
**PRODUCTION OF JP-4 JET FUEL**  
**BLOCK FLOW DIAGRAM**

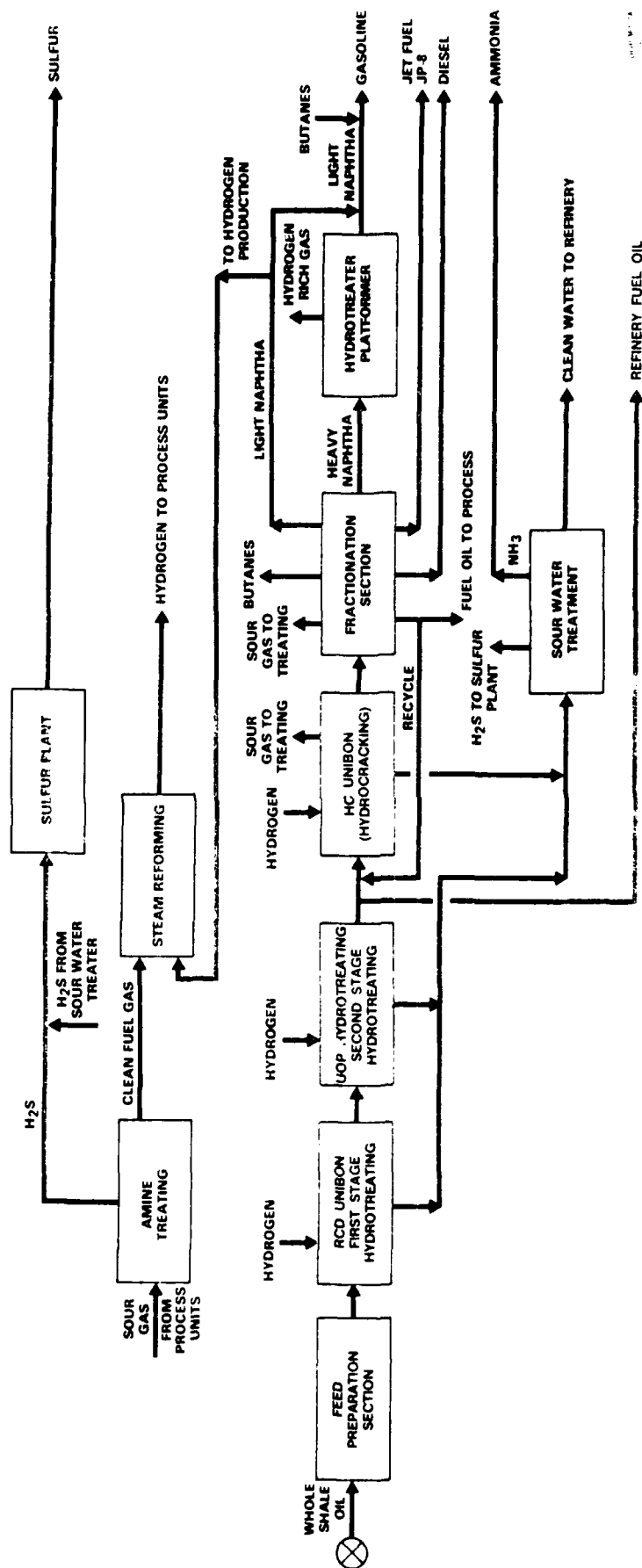


FIGURE 33  
PRODUCTION OF JP-8 JET FUEL  
BLOCK FLOW DIAGRAM

## APPENDIX A

### SAMPLE PREPARATION AND ANALYSIS FOR STABILITY/COMPATIBILITY STUDY

#### A.1 Preparation of Samples

##### A.1.1 Shale Oil Samples

1. Transfer 1850 cc of representative sample to a one-gallon bottle.
2. Place one-gallon bottle containing sample in sonic bath. Sonify at 80°F while bubbling in N<sub>2</sub> at 5 LHSV for 30 minutes to disperse and deoxygenate sample. Seal under N<sub>2</sub>.
3. Send samples for the following analysis stored under N<sub>2</sub>.

	<u>Sample Size, g</u>
Distillation (D-1160)	220
Micro C, H, O	1
Sulfur	1
Total N	1
Conradson Carbon	1
C <sub>7</sub> Insolubles	1
Toluene Insolubles	1
Viscosity, Kinematic at 100°F	40
Steam Jet Gum	100
Bromine Number	10
Metals by AAS: As, Fe, Ni, V	25
F 21-51 (300°F Accelerated Fuel Oil Stability Test)	60 (mL)
ASTM D 2274-74 (Oxidation Stability Test)	375
Three Months 110°F Dark Storage Stability	375

A.1.2 Petroleum Crude Oil Sample

1. To each of 3 one-gallon bottles, transfer 1850 cc of representative sample of petroleum crude oil.
2. Sonic disperse and deoxygenate sample as listed in A.1.1.2.
3. Send sample for analysis listed in A.1.1.3.

A.2 Preparation of Shale Oil/Petroleum Crude Oil Blends

1. Blends are prepared from sonic dispersed and deoxygenated samples. Transfer 300 cc  $\pm$  1 cc shale oil to 1 gallon bottle. Add 700 cc  $\pm$  1 cc petroleum crude oil.
2. Place sample blend in sonic bath. Sonify at 80°F while bubbling in N<sub>2</sub> at 5 LHSV for 5 minutes to disperse and deoxygenate sample. Seal under N<sub>2</sub>.
3. Send samples for the following analysis stored under N<sub>2</sub>.

	<u>Sample Size, g</u>
C <sub>7</sub> Insolubles	1
Toluene Insolubles	1
Viscosity, Kinematic at 100°F	40
Steam Jet Gum	100
F 21-51 (350°F Accelerated Fuel Oil Stability Test)	60 (mL)
ASTM D 2274-74 (Oxidation Stability Accelerated Method)	375
Three Months 110°F Dark Storage Stability	375

### A.3 Three Months 110°F Dark Storage Fuel Oil Stability Test

#### 1. Scope

- 1.1 This method covers the measurement of the stability of distillate fuel. The fuel is stored in vented Pyrex bottles for three months at 110°F to give an indication of the fuels potential long-term storage stability when stored at lower temperatures.

#### 2. Applicable Documents

##### 2.1 ASTM Standards:

- D 270 Sampling Petroleum and Petroleum Products
- D 2274 Test for Oxidation Stability of Distillate Fuel Oil Accelerated Method
- D 1500 ASTM Color of Petroleum Products
- D 381 ASTM Jet Evaporation, Adherent Gums

#### 3. Summary of Method

- 3.1 A measured volume of filtered fuel is stored in vented Pyrex bottles for three months at 110°F. After three months the samples are examined for color and sediment.

#### 4. Significance

- 4.1 This test is the most commonly used accelerated test for distillate fuel oils. Many studies have been made and it has been shown that 13 weeks at 110°F dark storage is equivalent, in most cases, to one year of ambient storage (12.1).

#### 5. Apparatus

- 5.1 Sample containers are Serum Pyrex Bottles (12.2). The total capacity of the container is 500 mL.

AD-A138 374

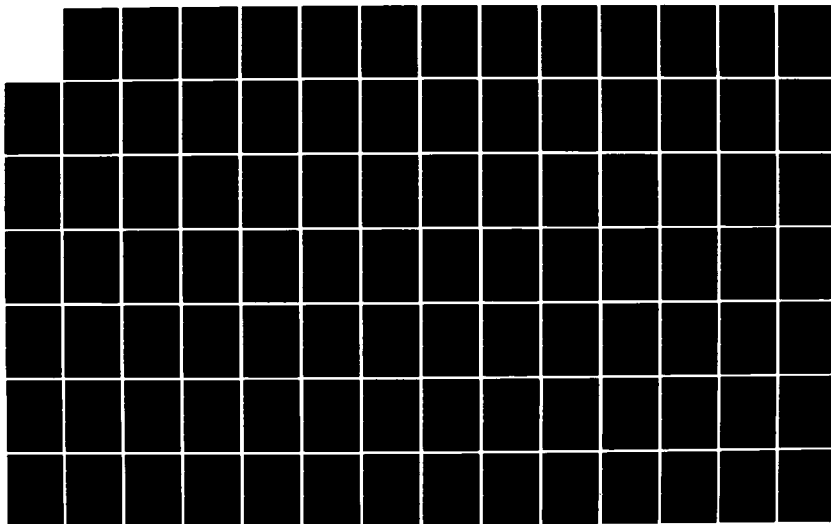
USAF SHALE OIL TO FUELS VOLUME 2 PHASES 3 AND 4(U) UOP  
INC DES PLAINES IL PROCESS DIV J G SIKONIA ET AL.  
JUL 82 AFMAL-TR-81-2116-VOL-2 F33615-78-C-2879

3/4

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- 5.2 A Miracle Top Box (12.3) with cover is used to store samples. Ends are open to allow ventilation.
- 5.3 A hot room is used to store samples. Temperature is thermostatically controlled to maintain a temperature of  $110^{\circ} \pm 1^{\circ}\text{F}$ .
- 5.4 Drying oven, maintained at  $194^{\circ} \pm 2^{\circ}\text{F}$ .
- 5.5 Filter holder, Millipore, Hydrosol Stainless, 47 mm, XX20 047 20.
- 5.6 Flash 21 filtering with side tube.
- 5.7 Petri dish.

6. Reagents and Materials

- 6.1 Filter, 0.8  $\mu$  Millipore Type AA.
- 6.2 Hydrocarbon solvent, n-heptane, 99% minimum purity, (Phillips Petroleum Company, or equivalent).
- 6.3 All equipment required to determine color by ASTM Method D 1500 (if desired).

7. Sampling Procedure

- 7.1 A sample for testing will be procured by the method outlined in ASTM Method D 270. Sample containers should preferably be 1-gallon or larger metal can. Sample containers should be rinsed with Adherent Insoluble Solvent (equal parts of reagent grade toluene, acetone, methanol), dried and then nitrogen filled. Samples should be stored at reduced temperature,  $33^{\circ}$  to  $45^{\circ}\text{F}$ , prior to use.

### A.3 Three Months 110°F Dark Storage Fuel Oil Stability Test

#### 1. Scope

- 1.1 This method covers the measurement of the stability of distillate fuel. The fuel is stored in vented Pyrex bottles for three months at 110°F to give an indication of the fuels potential long-term storage stability when stored at lower temperatures.

#### 2. Applicable Documents

##### 2.1 ASTM Standards:

- D 270 Sampling Petroleum and Petroleum Products
- D 2274 Test for Oxidation Stability of Distillate Fuel Oil Accelerated Method
- D 1500 ASTM Color of Petroleum Products
- D 381 ASTM Jet Evaporation, Adherent Gums

#### 3. Summary of Method

- 3.1 A measured volume of filtered fuel is stored in vented Pyrex bottles for three months at 110°F. After three months the samples are examined for color and sediment.

#### 4. Significance

- 4.1 This test is the most commonly used accelerated test for distillate fuel oils. Many studies have been made and it has been shown that 13 weeks at 110°F dark storage is equivalent, in most cases, to one year of ambient storage (12.1).

#### 5. Apparatus

- 5.1 Sample containers are Serum Pyrex Bottles (12.2). The total capacity of the container is 500 mL.

## 8. Preparation of Apparatus

- 8.1 Sample storage bottles. Rinse bottle with Adherent Insoluble solvent (equal parts of reagent grade toluene, acetone, methanol) and dry. If any stains are present, treat bottle first with chromic acid cleaning solution, rinse with water and dry.
- 8.2 Equilibrate the filter in a petri dish next to the balance for 30 minutes. Weigh filter to nearest 0.1 mg and retain for sample analysis. A "moisture blank" is run to correct for atmospheric moisture. Place the "moisture blank" filter in the petri dish, dry for 1 hour in an oven maintained at  $194^{\circ} \pm 2^{\circ}\text{F}$ . After drying place in desiccator (without desiccant) for at least 1 hour. One "moisture blank" filter is run for every four samples analyzed. The "moisture blank" filter should be weighed whenever the other four test filters are weighed and its change of weight subtracted from the level sample weight to correct for atmospheric moisture. The "moisture blank" filter is equilibrated in a petri dish next to the balance for 30 minutes before weighing.

## 9. Preparation of Sample

- 9.1 Prior to storage, the fuel oil shall be filtered through Whatman No. 2 filter paper at room temperature. Determine ASTM D 1500 color on unaged filtered fuel.

## 10. Procedure

- 10.1 Place 350 mL of filtered fuel in a bottle. Label storage bottle. Place in Miracle Top Box (Sec. 5.2) and store in hot room at  $110^{\circ} \pm 1^{\circ}\text{F}$  for 3 month dark storage.
- 10.2 At the end of the 3 month storage period remove the sample and cool to room temperature. Filter the aged sample under vacuum

(20-25 mm H<sub>2</sub>O) through a weighed filter (0.8 μ Millipore Type AA) in a millipore filter holder. Remove the filtrate and determine ASTM D 1500 color on aged filtered fuel. Rinse the storage bottle with n-heptane to remove all traces of fuel from the bottle, transferring each wash to the filter holder. Wash the filter paper and holder with n-heptane until free of fuel oil, using vacuum. The rinse filtrate can be discarded.

- 10.3 Transfer the filter to a petri dish, dry for 1 hour in an oven maintained at 194° ± 2°F. After drying place in desiccator (without desiccant) for at least 1 hour. Equilibrate the filter together with the "moisture blank" next to balance for 30 minutes. Weight to nearest 0.1 mg.

## 11. Calculations

- 11.1 Calculate the total sediment formation in milligrams per 100 mL after aging as follows:

$$A = \frac{B}{C} \times 100$$

where:

A = Total sediment, mg/100 mL

B = Weight of filterable sediment corrected for moisture using the "moisture blank"

C = Fuel placed in storage bottle, mL

## 12. References

- 12.1 Distillate Fuel Storage Stability Research conducted at Petroleum Experimental Station Bureau of Mines, Bartlesville,

Oklahoma -- Done for Western Petroleum Refining Association,  
October, 1958.

12.2 Bottle, Storage, (Centrifuge, original form) Pyrex, Corning, New  
Jersey, No. 1260; CGW code 423290, 500 mL cap. 73 mm dia., 173  
mm high.

12.3 Miracle Box No. 15, Paige Co., 432 Park Avenue South, New York,  
New York 10016.

A.4 Modification for Three Months 110°F Dark Storage Fuel Oil Stability  
Test

1. Store samples in vented Pyrex bottle for three months at 110°F  
as per Three Months 110°F Dark Storage Stability Test.
2. After three months storage, place sample in sonic bath for 30  
minutes.
3. Send samples for the following analysis:

C<sub>7</sub> Insolubles  
Toluene Insolubles  
Kinematic Viscosity at 100°F

4. Pour the remainder of sample into the bottle and store under  
N<sub>2</sub>. Wash the sample containers with three rinses (of about 50  
mL each) of cyclohexane. Discard cyclohexane rinse solution.
5. Dissolve any adherent gum on sample container wall with adherent  
insoluble solvent (equal parts of toluene, acetone and  
methanol). Determine the adherent insoluble content by evaporat-  
ing the solvent at 320°F (160°C) by the air-jet method described  
in Method D 381. Obtain weight of adherent insolubles in mg to  
0.1 mg.

A.5 Modification for F 21-61 (300°F Accelerated Fuel Oil Stability Test)

1. Follow steps (3), (4), and (5) of F 21-61 method.
2. After sample has cooled (step 5), place in sonic bath for 30 minutes.
3. Send sample for the following analysis:

C<sub>7</sub> Insolubles  
Toluene Insolubles  
Kinematic Viscosity

4. Pour the remainder of sample into the bottle and store under N<sub>2</sub>.

A.6 Modification for ASTM D 2274-74

1. Follow step (8.3) of ASTM D 2274-74 method.
2. After test, remove sample from bath and pour it into a 500 mL Erlenmeyer flask. Place the flask in a sonic bath for 30 minutes.
3. Sample for the following analysis:

C<sub>7</sub> Insolubles  
Toluene Insolubles  
Kinematic Viscosity at 100°F

4. Pour the remainder of sample into the bottle and store under N<sub>2</sub>.
5. Wash the sample container used in the ASTM D 2274-74 test and oxygen delivery tube with three rinsings (of about 50 mL each) of cyclohexane. Discard cyclohexane rinse solution.

6. Dissolve any adherent gum on container walls and oxygen delivery tube with the adherent insoluble solvent (equal parts of toluene, acetone and methanol). Determine the adherent insolubles content by evaporating the solvent at 320°F (160°C) by the air-jet method described in Method D 381. Obtain weight of adherent insolubles in mg to nearest 0.1 mg.

## A.7 Standard Analytical Methods

<u>Method Title</u>	<u>UOP Method No.*</u>	<u>ASTM Method No.**</u>
Distillation		D 1160
Heptane Insoluble Matter - Membrane Filter	U 614	
Toluene Insoluble Matter - Membrane Filter	Mod. U 614	
Conradson Carbon Residue of Petroleum Products		D 189
Viscosity, Kinematic at 100°F		D 445
Hydrogen and Carbon (Micro)	U 638	
Oxygen, Total, in Organic Materials	U 649	
Sulfur in Petroleum Products		D 1512
Nitrogen by Acid Extraction & Kjeldahl (495)	U 384	
Steam Jet Gum		D 381
300°F Accelerated Fuel Oil Stability Test	Mod. DuPont F 21-61	
Oxidation Stability of Distillate Fuel Oil		D 2274
Three Months 110°F Dark Storage Stability Test	***	
Metals in Petroleum Oil by AAS	800	
Bromine Number of Petroleum Distillates and Commerical Aliphatic Olefins by Electrometric Titration		D 1159
Modified Coulometric Sulfur	U 731	

\* "UOP Laboratory Test Methods for Petroleum and Its Products", UOP Process Division, Des Plaines, Illinois.

\*\* "1980 Annual Book ASTM Standards", American Society for Testing and Materials, Philadelphia, PA; 1980.

\*\*\* UOP Laboratory Test Method, not yet finalized.

# Appendix B.1

## MAXIMUM JP-4 CASE -- PROFORMA FINANCIAL STATEMENT

### ECONOMIC EVALUATION MODEL

RUN NUMBER 2

ALL \$ VALUES IN MILLIONS  
YEAR

### USAF SHALE OIL STUDY PROFORMA FINANCIAL STATEMENT

MAX. JPA-15% ROI

PAGE 1 -- 1

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PERCENT CAPACITY	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	865.76	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51
RAW MATERIAL COST	657.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	208.76	417.51	417.51	417.51	417.51	417.51	417.51	417.51	417.51	417.51
OPERATING LABOR	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80
UTILITY COST	10.19	20.38	20.38	20.38	20.38	20.38	20.38	20.38	20.38	20.38
MAINTENANCE COST	22.92	22.92	22.92	22.92	22.92	22.92	22.92	22.92	22.92	22.92
CAT+CHEN COST	4.39	8.78	8.78	8.78	8.78	8.78	8.78	8.78	8.78	8.78
DIRECT MFG EXPENSE	46.30	60.88	60.88	60.88	60.88	60.88	60.88	60.88	60.88	60.88
INSURANCE	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41
PROPERTY TAX	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83	8.83
INDIRECT MFG EXPENSE	13.24	13.24	13.24	13.24	13.24	13.24	13.24	13.24	13.24	13.24
DEPRECIATION	112.00	103.38	94.77	86.15	77.54	68.92	60.31	51.69	43.08	34.46
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	23.26	226.05	234.67	243.28	251.90	260.51	269.13	277.74	286.36	294.97
TAX LOSS DEDUCTION										
ADJ. TAXABLE INCOME	23.26	226.05	234.67	243.28	251.90	260.51	269.13	277.74	286.36	294.97
CURRENT TAX	1.63	113.03	117.33	121.64	125.95	130.26	134.56	138.87	143.18	147.49
TAX CREDITS	10.67	79.82	0.	0.	0.	0.	0	0.	0.	0.
TAXES PAYABLE	1.16	33.20	117.33	121.64	125.95	130.26	134.56	138.87	143.18	147.49
NET AFTER TAX INCOME	22.10	192.85	117.33	121.64	125.95	130.26	134.56	138.87	143.18	147.49
OPERATING CASH FLOW	134.10	296.23	212.10	207.79	203.49	199.18	194.87	190.56	186.26	181.95
DEBT RETIREMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET CASH FLOW	134.10	296.23	212.10	207.79	203.49	199.18	194.87	190.56	186.26	181.95

## ECONOMIC EVALUATION MODEL

RUN NUMBER 2

ALL \$ VALUES IN MILLIONS  
YEAR

MAX. JPA-15% ROI

PAGE 1 - 2

USAF SHALE OIL STUDY  
PROFORMA FINANCIAL STATEMENT

	1995	1996	1997	1998	1999	2000
PERCENT CAPACITY	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	1731.51	1731.51	1731.51	1731.51	1731.51	1731.51
RAW MATERIAL COST	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	417.51	417.51	417.51	417.51	417.51	417.51
OPERATING LABOR	8.80	8.80	8.80	8.80	8.80	8.80
UTILITY COST	20.38	20.38	20.38	20.38	20.38	20.38
MAINTENANCE COST	22.92	22.92	22.92	22.92	22.92	22.92
CAT+CHEM COST	8.78	8.78	8.78	8.78	8.78	8.78
DIRECT MFG EXPENSE	60.88	60.88	60.88	60.88	60.88	60.88
INSURANCE	4.41	4.41	4.41	4.41	4.41	4.41
PROPERTY TAX	8.83	8.83	8.83	8.83	8.83	8.83
INDIRECT MFG EXPENSE	13.24	13.24	13.24	13.24	13.24	13.24
DEPRECIATION	25.85	17.23	8.62			
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	303.59	312.20	320.82	329.44	329.44	329.44
TAX LOSS DEDUCTION						
ADJ. TAXABLE INCOME	303.59	312.20	320.82	329.44	329.44	329.44
CURRENT TAX	151.79	156.10	160.41	164.72	164.72	164.72
TAX CREDITS	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	151.79	156.10	160.41	164.72	164.72	164.72
NET AFTER TAX INCOME	151.79	156.10	160.41	164.72	164.72	164.72
OPERATING CASH FLOW	177.64	173.33	169.03	164.72	164.72	164.72
DEBT RETIREMENT	0.	0.	0.	0.	0.	0.
RETURN OF WORK. CAP.						118.00
NET CASH FLOW	177.64	173.33	169.03	164.72	164.72	164.72

Appendix B.1 (Cont.)

USAF SHALE OIL STUDY  
 PROFITABILITY SUMMARY  
 MAX. JP4-15% ROI  
 PAGE 2 - 1

ECONOMIC EVALUATION MODEL  
 RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

PAYBACK PERIOD: YEARS 4.26

AFTER TAX DISCOUNTED  
 RATE OF RETURN ON EQUITY % 15.00

AFTER TAX DISCOUNTED  
 RATE OF RETURN ON PROJECT % 15.00

NET PRESENT VALUE @15%: \$MM 101.09

N.P.V. INDEX @15% 0.11

\*\*\*\*\*

# Appendix B.1 (Cont.)

MAX. JPA-15% ROI  
PAGE 3 - 1

## BASIS FOR STUDY PROFITABILITY SUMMARY

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

### ECONOMIC PARAMETERS

PROJECT LIFE: YEARS	16
CONSTR PERIOD: YEARS	3
INTEREST RATE: %	0.000
INCOME TAX RATE: %	50.000
PERCENT DEBT	0.00
GENERAL INFLATION FACTOR	1.000
LABOR INFLATION FACTOR	1.000
UTILITY INFLATION FACTOR	1.000
PETRO PRODS INFL FACTOR	1.000
CONST COST INFL FACTOR	1.000
WORKING CAP INFL FACTOR	1.000
INV. TAX CREDIT: % OF CAP	10.00
INV TX CR: MAX % OF TAX	90.000

### BASE FEED PRICES

SHALE OIL 40.00

### BASE PRODUCT PRICES

JET FUEL \$/BBL	56.82
AMMONIA \$/ST	155.00
SULFUR \$/LT	105.00

### BASE WORKING CAPITAL

RAW MATERIALS	93.00
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
LAND	0.
CATALYST & CHEMICALS	25.00
ROYALTY & FEES	0.

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

ESTIMATED CAPITAL INVESTMT  
CONST. INFLATION FACTOR  
INTEREST RATE: %

YEAR	1982	1983	1984
% COMPLETION FOR YR	25.00	50.00	25.00

PLANT INVESTMENT  
CAPITAL INVESTMENT  
CONST. COST INFLATION  
CONST. COST FOR YEAR

TOTAL DEPRECIABLE INV.

OTHER INVESTMENT  
LAND  
INITIAL CAT. & CHEM.  
ROYALTY & FEES

SUBTOTAL

WORKING CAPITAL  
RAW MATERIALS  
ACCOUNTS RECEIVABLE  
ACCOUNTS PAYABLE  
NOBLE METALS  
INT ON CONSTRUCTION  
TOTAL CONST INTEREST

SUBTOTAL

TOTAL INVESTMENT

USAF SHALE OIL STUDY  
INVESTMENT SUMMARY

MAX. JPY-15% ROI

PAGE 4 - 1

# Appendix B.1 (Cont.)

## ECONOMIC EVALUATION MODEL

RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

USAF SHALE OIL STUDY  
PRODUCTION SUMMARY

MAX. JPA-15% ROI

PAGE 5 - 1

YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PRODUCTION, MM UNITS/YEAR										
JET FUEL (BBLs)	15.07	30.14	30.14	30.14	30.14	30.14	30.14	30.14	30.14	30.14
ANTHRA (ST)	0.05	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: \$/UNIT										
JET FUEL \$/BBL	56.82	56.82	56.82	56.82	56.82	56.82	56.82	56.82	56.82	56.82
ANTHRA \$/ST	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR \$/LT	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES \$MM/YEAR										
JET FUEL	856.42	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85
ANTHRA	2.86	5.72	5.72	5.72	5.72	5.72	5.72	5.72	5.72	5.72
SULFUR	0.83	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66

Appendix B.1 (Cont.)

MAX. JP4-15% ROI

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## ECONOMIC EVALUATION MODEL

RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

USAF SHALE OIL STUDY  
PRODUCTION SUMMARY

YEAR	1995	1996	1997	1998	1999	2000
PRODUCTION, MM UNITS/YEAR						
JET FUEL (BBLs)	30.14	30.14	30.14	30.14	30.14	30.14
ANTONIA (ST)	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: \$/UNIT						
JET FUEL \$/BBL	56.82	56.82	56.82	56.82	56.82	56.82
ANTONIA \$/ST	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR \$/LT	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES \$MM/YEAR						
JET FUEL	1712.85	1712.85	1712.85	1712.85	1712.85	1712.85
ANTONIA	5.72	5.72	5.72	5.72	5.72	5.72
SULFUR	1.66	1.66	1.66	1.66	1.66	1.66

## Appendix B.2

## JP-4 PLUS DIESEL CASE -- PROFORMA FINANCIAL STATEMENT

## ECONOMIC EVALUATION MODEL

JP4+DIESEL-15% ROI

RUN NUMBER		2		USAF SHALE OIL STUDY PROFORMA FINANCIAL STATEMENT											PAGE		1 - 1	
ALL \$ VALUES IN MILLIONS YEAR		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994							
PERCENT CAPACITY		50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00							
ANNUAL SALES		886.76	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53	1773.53							
RAW MATERIAL COST		657.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00							
GROSS MARGIN		229.76	459.53	459.53	459.53	459.53	459.53	459.53	459.53	459.53	459.53							
OPERATING LABOR		9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98							
UTILITY COST		13.29	26.58	26.58	26.58	26.58	26.58	26.58	26.58	26.58	26.58							
MAINTENANCE COST		25.62	25.62	25.62	25.62	25.62	25.62	25.62	25.62	25.62	25.62							
CAT+CHEM COST		4.06	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11							
DIRECT MFG EXPENSE		52.94	70.29	70.29	70.29	70.29	70.29	70.29	70.29	70.29	70.29							
INSURANCE		4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85							
PROPERTY TAX		9.70	9.70	9.70	9.70	9.70	9.70	9.70	9.70	9.70	9.70							
INDIRECT MFG EXPENSE		14.55	14.55	14.55	14.55	14.55	14.55	14.55	14.55	14.55	14.55							
DEPRECIATION		124.66	115.25	105.65	96.04	86.44	76.84	67.23	57.63	48.02	38.42							
INTEREST ON W. CAPITAL		13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95							
TAXABLE INCOME		23.46	245.49	255.10	264.70	274.30	283.91	293.51	303.12	312.72	322.33							
TAX LOSS DEDUCTION																		
ADJ. TAXABLE INCOME		23.46	245.49	255.10	264.70	274.30	283.91	293.51	303.12	312.72	322.33							
CURRENT TAX		11.73	122.75	127.55	132.35	137.15	141.95	146.76	151.56	156.36	161.16							
TAX CREDITS		10.56	88.43	0.	0.	0.	0.	0.	0.	0.	0.							
TAXES PAYABLE		1.17	34.32	127.55	132.35	137.15	141.95	146.76	151.56	156.36	161.16							
NET AFTER TAX INCOME		22.29	211.18	127.55	132.35	137.15	141.95	146.76	151.56	156.36	161.16							
OPERATING CASH FLOW		147.15	326.43	233.20	228.39	223.59	218.79	213.99	209.18	204.38	199.58							
DEBT RETIREMENT		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00							
NET CASH FLOW		147.15	326.43	233.19	228.39	223.59	218.79	213.99	209.18	204.38	199.58							

JP4+DIESEL-15% ROI  
PAGE 1 - 2

ECONOMIC EVALUATION MODEL		USAF SHALE OIL STUDY PROFORMA FINANCIAL STATEMENT					
RUN NUMBER	2	1995	1996	1997	1998	1999	2000
ALL \$ VALUES IN MILLIONS							
YEAR							
PERCENT CAPACITY		100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES		1773.53	1773.53	1773.53	1773.53	1773.53	1773.53
RAW MATERIAL COST		1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN		459.53	459.53	459.53	459.53	459.53	459.53
OPERATING LABOR		9.98	9.98	9.98	9.98	9.98	9.98
UTILITY COST		26.58	26.58	26.58	26.58	26.58	26.58
MAINTENANCE COST		25.62	25.62	25.62	25.62	25.62	25.62
CAT+CHEM COST		8.11	8.11	8.11	8.11	8.11	8.11
DIRECT MFG EXPENSE		70.29	70.29	70.29	70.29	70.29	70.29
INSURANCE		4.85	4.85	4.85	4.85	4.85	4.85
PROPERTY TAX		9.70	9.70	9.70	9.70	9.70	9.70
INDIRECT MFG EXPENSE		14.55	14.55	14.55	14.55	14.55	14.55
DEPRECIATION		28.81	19.21	9.61			
INTEREST ON W. CAPITAL		13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME		331.93	341.53	351.14	360.74	360.74	360.74
TAX LOSS DEDUCTION							
ADJ. TAXABLE INCOME		331.93	341.53	351.14	360.74	360.74	360.74
CURRENT TAX		165.97	170.77	175.57	180.37	180.37	180.37
TAX CREDITS		0.	0.	0.	0.	0.	0.
TAXES PAYABLE		165.97	170.77	175.57	180.37	180.37	180.37
NET AFTER TAX INCOME		165.96	170.77	175.57	180.37	180.37	180.37
OPERATING CASH FLOW		194.78	189.98	185.17	180.37	180.37	180.37
DEBT RETIREMENT		0.	0.	0.	0.	0.	0.
RETURN OF WORK. CAP.							115.00
NET CASH FLOW		194.78	189.98	185.17	180.37	180.37	180.37

JP4-DIESEL-15% ROI  
PAGE 2 - 1

USAF SHALE OIL STUDY  
PROFITABILITY SUMMARY

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

PAYBACK PERIOD: YEARS 4.24

AFTER TAX DISCOUNTED  
RATE OF RETURN ON EQUITY % 15.00

AFTER TAX DISCOUNTED  
RATE OF RETURN ON PROJECT % 15.00

NET PRESENT VALUE @15%: \$MM 111.05

N.P.V. INDEX @15% 0.11

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BASIS FOR STUDY  
PROFITABILITY SUMMARY  
JP4+DIESEL-15% ROI  
PAGE 3 - 1

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

#### ECONOMIC PARAMETERS

PROJECT LIFE: YEARS	16
CONSTR PERIOD: YEARS	3
INTEREST RATE: %	0.000
INCOME TAX RATE: %	50.000
PERCENT DEBT	0.00
GENERAL INFLATION FACTOR	1.000
LABOR INFLATION FACTOR	1.000
UTILITY INFLATION FACTOR	1.000
PETRO PRODS INFL FACTOR	1.000
CONST COST INFL FACTOR	1.000
WORKING CAP INFL FACTOR	1.000
INV. TAX CREDIT: % OF CAP	10.00
INV TX CR: MAX % OF TAX	90.000

#### BASE FEED PRICES

SHALE OIL	40.00
-----------	-------

#### BASE PRODUCT PRICES

JET FUEL \$/EBL	58.82
ANTHRA \$/ST	155.00
SULFUR \$/LT	105.00

#### BASE WORKING CAPITAL

RAW MATERIALS	93.00
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
LAND	0.
CATALYST & CHEMICALS	22.00
ROYALTY & FEES	0.

JP4+DIESEL-15% ROI  
PAGE 4 - 1

USAF SHALE OIL STUDY  
INVESTMENT SUMMARY

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

ESTIMATED CAPITAL INVESTMT 874.00  
CONST. INFLATION FACTOR 1.000  
INTEREST RATE: % 0.000

YEAR	1982	1983	1984
% COMPLETION FOR YR	25.00	50.00	25.00

PLANT INVESTMENT	1982	1983	1984
CAPITAL INVESTMENT	218.50	437.00	218.50
CONST. COST INFLATION	-0.00	-0.00	-0.00
CONST. COST FOR YEAR	218.50	437.00	218.50

TOTAL DEPRECIABLE INV. 874.00

OTHER INVESTMENT	0.
LAND	22.00
INITIAL CAT. & CHEM.	0.
ROYALTY & FEES	0.
SUBTOTAL	22.00

WORKING CAPITAL	93.00
RAW MATERIALS	0.
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
INT ON CONSTRUCTION	0.
TOTAL CONST INTEREST	0.
SUBTOTAL	93.00

TOTAL INVESTMENT 999.00

ECONOMIC EVALUATION MODEL		JP4+DIESEL-15% ROI									
RUN NUMBER 2		USAF SHALE OIL STUDY									
ALL \$ VALUES IN MILLIONS		PRODUCTION SUMMARY									
		PAGE 5 - 1									
YEAR		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PRODUCTION, MM UNITS/YEAR											
JET FUEL (BBL)		14.92	29.84	29.84	29.84	29.84	29.84	29.84	29.84	29.84	29.84
ANTHRA (ST)		0.05	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)		0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: \$/UNIT											
JET FUEL \$/BBL		58.82	58.82	58.82	58.82	58.82	58.82	58.82	58.82	58.82	58.82
ANTHRA \$/ST		155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR \$/LT		105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES \$MM/YEAR											
JET FUEL		877.43	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86
ANTHRA		2.96	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92	5.92
SULFUR		0.86	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71

JP4-DIESEL-15% ROI  
PAGE 5 - 2

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2  
ALL \$ VALUES IN MILLIONS

USAF SHALE OIL STUDY  
PRODUCTION SUMMARY

YEAR	1995	1996	1997	1998	1999	2000
PRODUCTION, MM UNITS/YEAR						
JET FUEL (BBLs)	29.84	29.84	29.84	29.84	29.84	29.84
ATFONIA (ST)	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: \$/UNIT						
JET FUEL \$/BBL	58.82	58.82	58.82	58.82	58.82	58.82
ATFONIA \$/ST	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR \$/LT	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES \$MM/YEAR						
JET FUEL	1754.86	1754.86	1754.86	1754.86	1754.86	1754.86
ATFONIA	5.92	5.92	5.92	5.92	5.92	5.92
SULFUR	1.71	1.71	1.71	1.71	1.71	1.71

# Appendix B.3

## MAXIMUM JP-8 CASE -- PROFORMA FINANCIAL STATEMENT

ECONOMIC EVALUATION MODEL		USAF SHALE OIL STUDY										MAX. JP8-15% ROI	
RUN NUMBER	2	PROFORMA FINANCIAL STATEMENT										PAGE 1 - 1	
ALL \$ VALUES IN MILLIONS		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994		
PERCENT CAPACITY		50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		
ANNUAL SALES		874.55	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10		
RAW MATERIAL COST		657.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00		
GROSS MARGIN		217.55	435.10	435.10	435.10	435.10	435.10	435.10	435.10	435.10	435.10		
OPERATING LABOR		10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16		
UTILITY COST		10.68	21.36	21.36	21.36	21.36	21.36	21.36	21.36	21.36	21.36		
MAINTENANCE COST		23.97	23.97	23.97	23.97	23.97	23.97	23.97	23.97	23.97	23.97		
CATCHER COST		4.49	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98	8.98		
DIRECT MFG EXPENSE		49.30	64.47	64.47	64.47	64.47	64.47	64.47	64.47	64.47	64.47		
INSURANCE		4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60		
PROPERTY TAX		9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20		
INDIRECT MFG EXPENSE		13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80		
DEPRECIATION		117.00	108.00	99.00	90.00	81.00	72.00	63.00	54.00	45.00	36.00		
INTEREST ON W. CAPITAL		13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95	13.95		
TAXABLE INCOME		23.50	234.88	243.88	252.88	261.88	270.88	279.88	288.88	297.88	306.88		
TAX LOSS DEDUCTION													
ADJ. TAXABLE INCOME		23.50	234.88	243.88	252.88	261.88	270.88	279.88	288.88	297.88	306.88		
CURRENT TAX		11.75	117.44	121.94	126.44	130.94	135.44	139.94	144.44	148.94	153.44		
TAX CREDITS		10.58	83.41	0.	0.	0.	0.	0.	0.	0.	0.		
TAXES PAYABLE		1.17	34.02	121.94	126.44	130.94	135.44	139.94	144.44	148.94	153.44		
NET AFTER TAX INCOME		22.33	200.85	121.94	126.44	130.94	135.44	139.94	144.44	148.94	153.44		
OPERATING CASH FLOW		139.33	308.85	220.94	216.44	211.94	207.44	202.94	198.44	193.94	189.44		
DEBT RETIREMENT		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
NET CASH FLOW		139.33	308.85	220.94	216.44	211.94	207.44	202.94	198.44	193.94	189.44		

MAX. JPB-15% ROI

PAGE 1 -

## ECONOMIC EVALUATION MODEL

RUN NUMBER 2

ALL \$ VALUES IN MILLIONS  
YEARUSAF SHALE OIL STUDY  
PROFORMA FINANCIAL STATEMENT

	1995	1996	1997	1998	1999	2000
PERCENT CAPACITY	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	1749.10	1749.10	1749.10	1749.10	1749.10	1749.10
RAW MATERIAL COST	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	435.10	435.10	435.10	435.10	435.10	435.10
OPERATING LABOR	10.16	10.16	10.16	10.16	10.16	10.16
UTILITY COST	21.36	21.36	21.36	21.36	21.36	21.36
MAINTENANCE COST	23.97	23.97	23.97	23.97	23.97	23.97
CAT+CHEM COST	8.98	8.98	8.98	8.98	8.98	8.98
DIRECT MFG EXPENSE	64.47	64.47	64.47	64.47	64.47	64.47
INSURANCE	4.60	4.60	4.60	4.60	4.60	4.60
PROPERTY TAX	9.20	9.20	9.20	9.20	9.20	9.20
INDIRECT MFG EXPENSE	13.80	13.80	13.80	13.80	13.80	13.80
DEPRECIATION	27.00	18.00	9.00			
INTEREST ON W. CAPITAL	13.95	13.95	13.95	13.95	13.95	13.95
TAXABLE INCOME	315.88	324.88	333.88	342.88	342.88	342.88
TAX LOSS DEDUCTION						
ADJ. TAXABLE INCOME	315.88	324.88	333.88	342.88	342.88	342.88
CURRENT TAX	157.94	162.44	166.94	171.44	171.44	171.44
TAX CREDITS	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	157.94	162.44	166.94	171.44	171.44	171.44
NET AFTER TAX INCOME	157.94	162.44	166.94	171.44	171.44	171.44
OPERATING CASH FLOW	184.94	180.44	175.94	171.44	171.44	171.44
DEBT RETIREMENT	0.	0.	0.	0.	0.	0.
RETURN OF WORK. CAP.						120.00
NET CASH FLOW	184.94	180.44	175.94	171.44	171.44	171.44

ECONOMIC EVALUATION MODEL  
 RUN NUMBER 2  
 ALL \$ VALUES IN MILLIONS  
 PAYBACK PERIOD: YEARS 4.26  
 AFTER TAX DISCOUNTED  
 RATE OF RETURN ON EQUITY % 15.00  
 AFTER TAX DISCOUNTED  
 RATE OF RETURN ON PROJECT % 15.00  
 NET PRESENT VALUE @15%: \$11 105.25  
 N.P.V. INDEX @15% 0.11

USAF SHALE OIL STUDY  
 PROFITABILITY SUMMARY

MAX. JPB-15% ROI

PAGE 2 - 1

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BASIS FOR STUDY  
PROFITABILITY SUMMARY

MAX. JPB-15% ROI

PAGE 1 - 1

Appendix B.3 (Cont.)

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

ECONOMIC PARAMETERS

PROJECT LIFE: YEARS	16
CONSTR PERIOD: YEARS	3
INTEREST RATE: %	0.000
INCOME TAX RATE: %	50.000
PERCENT DEBT	0.00
GENERAL INFLATION FACTOR	1.000
LABOR INFLATION FACTOR	1.000
UTILITY INFLATION FACTOR	1.000
PETRO PRODS INFL FACTOR	1.000
CONST COST INFL FACTOR	1.000
WORKING CAP INFL FACTOR	1.000
INV. TAX CREDIT: % OF CAP	10.00
INV TX CR: MAX % OF TAX	90.000

BASE FEED PRICES

SHALE OIL	40.00
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BASE PRODUCT PRICES

JET FUEL \$/BBL	58.80
AMONIA \$/ST	155.00
SULFUR \$/LT	105.00

BASE WORKING CAPITAL

RAW MATERIALS	93.00
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
LAND	0.
CATALYST & CHEMICALS	27.00
ROYALTY & FEES	0.

# Appendix B.3 (Cont.)

ECONOMIC EVALUATION MODEL		USAF SHALE OIL STUDY		MAX. JP8-15% ROI	
RUN NUMBER 2		INVESTMENT SUMMARY			
ALL \$ VALUES IN MILLIONS					
ESTIMATED CAPITAL INVESTMT					
CONST. INFLATION FACTOR					
INTEREST RATE: %					
YEAR					
% COMPLETION FOR YR					
PLANT INVESTMENT					
CAPITAL INVESTMENT					
CONST. COST INFLATION					
CONST. COST FOR YEAR					
TOTAL DEPRECIABLE INV.					
OTHER INVESTMENT					
LAND					
INITIAL CAT.&CHEM.					
ROYALTY & FEES					
SUBTOTAL					
WORKING CAPITAL					
RAW MATERIALS					
ACCOUNTS RECEIVABLE					
ACCOUNTS PAYABLE					
NOBLE METALS					
INT ON CONSTRUCTION					
TOTAL CONST INTEREST					
SUBTOTAL					
TOTAL INVESTMENT					

## ECONOMIC EVALUATION MODEL

RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

MAX. JPB-15% ROI

USAF SHALE OIL STUDY  
PRODUCTION SUMMARY

PAGE 5 - 1

YEAR	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PRODUCTION, MM UNITS/YEAR										
JET FUEL (BBL/S)	14.72	29.43	29.43	29.43	29.43	29.43	29.43	29.43	29.43	29.43
ATTOMIA (ST)	0.05	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: \$/UNIT										
JET FUEL \$/BBL	58.80	58.80	58.80	58.80	58.80	58.80	58.80	58.80	58.80	58.80
ATTOMIA \$/ST	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR \$/LT	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES \$MM/YEAR										
JET FUEL	865.19	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38	1730.38
ATTOMIA	2.97	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94
SULFUR	0.66	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71

ECONOMIC EVALUATION MODEL		USAF SHALE OIL STUDY PRODUCTION SUMMARY					MAX. JP8-15% ROI
RUN NUMBER	2						PAGE 5 - 2
ALL \$ VALUES IN MILLIONS							
YEAR		1995	1996	1997	1998	1999	2000
PRODUCTION, MM UNITS/YEAR							
JET FUEL (BBLs)		29.43	29.43	29.43	29.43	29.43	29.43
ATKONIA (ST)		0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)		0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: \$/UNIT							
JET FUEL \$/BBL		58.80	58.80	58.80	58.80	58.80	58.80
ATKONIA \$/ST		155.00	155.00	155.00	155.00	155.00	155.00
SULFUR \$/LT		105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES \$MM/YEAR							
JET FUEL		1730.38	1730.38	1730.38	1730.38	1730.38	1730.38
ATKONIA		5.94	5.94	5.94	5.94	5.94	5.94
SULFUR		1.71	1.71	1.71	1.71	1.71	1.71

## Appendix B.4

## JP-8 PLUS DIESEL CASE -- PROFORMA FINANCIAL STATEMENT

## ECONOMIC EVALUATION MODEL

RUN NUMBER 2

USAF SHALE OIL STUDY  
PROFORMA FINANCIAL STATEMENT

JP8+DIESEL-15% ROI

PAGE 1 - 1

ALL \$ VALUES IN MILLIONS  
YEAR

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PERCENT CAPACITY	50.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
ANNUAL SALES	865.94	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88	1731.88
RAW MATERIAL COST	657.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN	208.94	417.88	417.88	417.88	417.88	417.88	417.88	417.88	417.88	417.88
OPERATING LABOR	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16	10.16
UTILITY COST	9.32	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64	18.64
MAINTENANCE COST	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10
CAT+CHEM COST	4.18	8.37	8.37	8.37	8.37	8.37	8.37	8.37	8.37	8.37
DIRECT MFG EXPENSE	46.77	60.27	60.27	60.27	60.27	60.27	60.27	60.27	60.27	60.27
INSURANCE	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43
PROPERTY TAX	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86
INDIRECT MFG EXPENSE	13.29	13.29	13.29	13.29	13.29	13.29	13.29	13.29	13.29	13.29
DEPRECIATION	112.86	104.18	95.49	86.81	78.13	69.45	60.77	52.09	43.41	34.73
INTEREST ON W. CAPITAL	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80
TAXABLE INCOME	22.23	226.34	235.02	243.70	252.38	261.06	269.75	278.43	287.11	295.79
TAX LOSS DEDUCTION										
ADJ. TAXABLE INCOME	22.23	226.34	235.02	243.70	252.38	261.06	269.75	278.43	287.11	295.79
CURRENT TAX	11.11	113.17	117.51	121.85	126.19	130.53	134.87	139.21	143.55	147.89
TAX CREDITS	10.00	80.59	0.	0.	0.	0.	0.	0.	0.	0.
TAXES PAYABLE	1.11	32.58	117.51	121.85	126.19	130.53	134.87	139.21	143.55	147.89
NET AFTER TAX INCOME	21.12	193.76	117.51	121.85	126.19	130.53	134.87	139.21	143.55	147.89
OPERATING CASH FLOW	133.97	297.93	213.00	208.66	204.32	199.98	195.64	191.30	186.96	182.62
DEBT RETIREMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET CASH FLOW	133.97	297.93	213.00	208.66	204.32	199.98	195.64	191.30	186.96	182.62

ECONOMIC EVALUATION MODEL		JP8-DIESEL-15% ROI				
RUN NUMBER	2	USAF SHALE OIL STUDY				
ALL \$ VALUES IN MILLIONS		PROFORMA FINANCIAL STATEMENT				
YEAR		1995	1996	1997	1998	1999
PERCENT CAPACITY		100.00	100.00	100.00	100.00	100.00
ANNUAL SALES		1731.88	1731.88	1731.88	1731.88	1731.88
RAW MATERIAL COST		1314.00	1314.00	1314.00	1314.00	1314.00
GROSS MARGIN		417.88	417.88	417.88	417.88	417.88
OPERATING LABOR		10.16	10.16	10.16	10.16	10.16
UTILITY COST		18.64	18.64	18.64	18.64	18.64
MAINTENANCE COST		23.10	23.10	23.10	23.10	23.10
CAT+CHEM COST		8.37	8.37	8.37	8.37	8.37
DIRECT MFG EXPENSE		60.27	60.27	60.27	60.27	60.27
INSURANCE		4.43	4.43	4.43	4.43	4.43
PROPERTY TAX		8.86	8.86	8.86	8.86	8.86
INDIRECT MFG EXPENSE		13.29	13.29	13.29	13.29	13.29
DEPRECIATION		26.04	27.36	6.68		
INTEREST ON W. CAPITAL		13.80	13.80	13.80	13.80	13.80
TAXABLE INCOME		304.47	313.15	321.83	330.51	330.51
TAX LOSS DEDUCTION						
ADJ. TAXABLE INCOME		304.47	313.15	321.83	330.51	330.51
CURRENT TAX		152.24	156.58	160.92	165.26	165.26
TAX CREDIT'S		0.	0.	0.	0.	0.
TAXES PAYABLE		152.24	156.58	160.92	165.26	165.26
NET AFTER TAX INCOME		152.24	156.58	160.92	165.26	165.26
OPERATING CASH FLOW		178.28	173.94	169.60	165.26	165.26
DEBT RETIREMENT		0.	0.	0.	0.	0.
RETURN OF WORK. CAP.						115.00
NET CASH FLOW		178.28	173.94	169.60	165.26	165.26

JP8-DIESEL-15% ROI  
PAGE 2 - 1

USAF SHALE OIL STUDY  
PROFITABILITY SUMMARY

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

PAYBACK PERIOD: YEARS 4.26

AFTER TAX DISCOUNTED  
RATE OF RETURN ON EQUITY % 15.00

AFTER TAX DISCOUNTED  
RATE OF RETURN ON PROJECT % 15.00

NET PRESENT VALUE @15%: \$111 101.44

N.P.V. INDEX @15% 0.11

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JP8-DIESEL-15% ROI  
PAGE 3 - 1BASIS FOR STUDY  
PROFITABILITY SUMMARYECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

## ECONOMIC PARAMETERS

PROJECT LIFE: YEARS	16
CONSTR PERIOD: YEARS	3
INTEREST RATE: %	0.000
INCOME TAX RATE: %	50.000
PERCENT DEBT	0.00
GENERAL INFLATION FACTOR	1.000
LABOR INFLATION FACTOR	1.000
UTILITY INFLATION FACTOR	1.000
PETRO PRODS INFL FACTOR	1.000
CONST COST INFL FACTOR	1.000
WORKING CAP INFL FACTOR	1.000
INV. TAX CREDIT: % OF CAP	10.00
INV TX CR: MAX % OF TAX	90.000

## BASE FEED PRICES

SHALE OIL	40.00
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## BASE PRODUCT PRICES

JET FUEL \$/BSL	58.85
AMMONIA \$/ST	155.00
SULFUR \$/LT	105.00

## BASE WORKING CAPITAL

RAW MATERIALS	92.00
ACCOUNTS RECEIVABLE	0.
ACCOUNTS PAYABLE	0.
NOBLE METALS	0.
LAND	0.
CATALYSTS & CHEMICALS	23.00
ROYALTY & FEES	0.

Appendix B.4 (Cont.)

JP8-DIESEL-15% ROI PAGE 4 - 1

USAF SHALE OIL STUDY  
INVESTMENT SUMMARY

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2

ALL \$ VALUES IN MILLIONS

ESTIMATED CAPITAL INVESTMT 790.00  
CONST. INFLATION FACTOR 1.000  
INTEREST RATE: % 0.000

YEAR	1982	1983	1984
% COMPLETION FOR YR	25.00	50.00	25.00

PLANT INVESTMENT	197.50	395.00	197.50
. CAPITAL INVESTMENT	197.50	395.00	197.50
. CONST. COST INFLATION	-0.00	-0.00	-0.00
. CONST. COST FOR YEAR	197.50	395.00	197.50

TOTAL DEPRECIABLE INV. 790.00

OTHER INVESTMENT	0.
. LAND	23.00
. INITIAL CAT.&CHEM.	0.
. ROYALTY & FEES	23.00
SUBTOTAL	23.00

WORKING CAPITAL	92.00
. RAW MATERIALS	0.
. ACCOUNTS RECEIVABLE	0.
. ACCOUNTS PAYABLE	0.
. NOBLE METALS	0.
. INT ON CONSTRUCTION	0.
TOTAL CONST INTEREST	0.
SUBTOTAL	92.00

TOTAL INVESTMENT 905.00

ECONOMIC EVALUATION MODEL		JP8-DIESEL-15% ROI									
RUN NUMBER 2		PAGE 5 - 1									
ALL \$ VALUES IN MILLIONS		USAF SHALE OIL STUDY PRODUCTION SUMMARY									
YEAR		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
PRODUCTION, MM UNITS/YEAR											
JET FUEL (BBLs)		14.56	29.11	29.11	29.11	29.11	29.11	29.11	29.11	29.11	29.11
ATMORIA (ST)		0.03	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)		0.01	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: \$/UNIT											
JET FUEL \$/BBL		58.95	58.85	58.85	58.85	58.85	58.85	58.85	58.85	58.85	58.85
ATMORIA \$/ST		155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR \$/LT		105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES \$MM/YEAR											
JET FUEL		856.58	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16
ATMORIA		2.97	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94	5.94
SULFUR		0.86	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71

JP8-DIESEL-15% ROI  
PAGE 5 - 2

ECONOMIC EVALUATION MODEL  
RUN NUMBER 2  
ALL \$ VALUES IN MILLIONS

USAF SHALE OIL STUDY  
PRODUCTION SUMMARY

YEAR	1995	1996	1997	1998	1999	2000
PRODUCTION, MM UNITS/YEAR						
JET FUEL (BBLs)	29.11	29.11	29.11	29.11	29.11	29.11
ATLONIA (ST)	0.10	0.10	0.10	0.10	0.10	0.10
SULFUR (LT)	0.03	0.03	0.03	0.03	0.03	0.03
PRODUCT PRICES: \$/UNIT						
JET FUEL \$/BBL	58.85	58.85	58.85	58.85	58.85	58.85
ATLONIA \$/ST	155.00	155.00	155.00	155.00	155.00	155.00
SULFUR \$/LT	105.00	105.00	105.00	105.00	105.00	105.00
PRODUCT VALUES \$MM/YEAR						
JET FUEL	1713.16	1713.16	1713.16	1713.16	1713.16	1713.16
ATLONIA	5.94	5.94	5.94	5.94	5.94	5.94
SULFUR	1.71	1.71	1.71	1.71	1.71	1.71

# Appendix B.5

## MAXIMUM JP-4 CASE -- STANDARD OPTIMIZATION REPORT

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USAF SHALE OIL TO FUELS

PHASE IV

CASE 1 - MAXIMUM JP-4 JET FUEL

### GROSS MARGIN SUMMARY

SALES	MARKET	PRODUCT	MAXIMUM	QUANTITY LIMITS MINIMUM	FIXED	QUANTITY SOLD	PRICE	TOTAL \$/DAY
A		AV TURBINE FUEL JP-4				82583.75 BBL	56.8200	4692408.7
A		SULFUR				87.79 TON	95.4500	8379.53
A		ANTHRAKITE				275.84 TON	155.0000	42754.63
TOTAL SALES REVENUE								4743592.83

RAW MATERIAL PURCHASED	MATERIAL	QUANTITY LIMITS	QUANTITY PURCHASED	PRICE	TOTAL
	OCCIDENTAL SHALE OIL	90000.0	90000.00 BBL	40.0000	3600000.00
	COLD TREATED WATER		14418.41 BBL	.0245	353.25
	50% STRIPPING STEAM		159.45 TON	.0000	.00

TOTAL RAW MATERIAL COST 3600353.25

GROSS MARGIN

1143189.58

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 USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

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Appendix B.5 (Cont.)

OPERATING COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	QUANTITY TON/D	\$/BBL	\$/TON	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.029556	.18419	2660.05
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.294147	1.83308	26473.23
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.238964	1.53820	22134.96
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	84601.3	12408.39	.687944	4.69045	58200.93
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	24850.2	2843.75	.052302	.45704	1299.71
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	17915.8	1946.07	.065593	.60385	1175.14
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		1335.36		.56680	756.88
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.22		19.67483	1932.48
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		737.30		39.50067	29123.72
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17534.2	3069.99	.207814	1.18693	3643.86
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.22		17.81405	1749.71
ANTONIA PLANT	COMBINED MODES	COMPOSITE COST		275.84		2.68881	741.67
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	13824.2	2027.59	.076524	.52174	1057.88
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.098029	.61090	8822.57
TOTAL PROCESS UNIT OPERATING COST							159772.79
UTILITY PURCHASES	UTILITY	UNIT	UNITS/D	\$/UNIT			\$/D
BOILER WATER		MLBS	4839.81	.50000			2419.91
TOTAL UTILITY PURCHASES							2419.91
UTILITY PRODUCTION COSTS	UTILITY	UNIT	UNITS/D				\$/D
600# STEAM		MLBS	4564.99				3112.49
TOTAL UTILITY PRODUCTION COSTS							3112.49
TOTAL OPERATING COST							165305.19

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0  
 USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

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CAPITAL COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY BBL/D	TON/D	\$/BBL	CAPITAL COST \$/TON	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.096215	.59960	8659.38
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.633231	1.94621	56990.78
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.997898	6.42342	92434.31
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	84601.3	12408.39	1.910045	13.02282	161592.23
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	24850.2	2843.75	.090110	.78742	2239.24
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	17915.8	1946.07	.218830	2.01459	3920.52
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		1335.36		1.18287	1579.56
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.22		57.37486	5635.41
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		737.30		162.24240	119620.79
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17534.2	3069.99	.530932	3.03242	9309.49
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.22		26.64155	2616.75
ATTORXIA PLANT	COMBINED MODES	COMPOSITE COST		275.84		1.50765	415.86
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	13824.2	2027.59	.211972	1.44524	2930.36
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.115235	.71813	10371.11
TOTAL							478315.80

Appendix B.5 (Cont.)

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

## MATERIAL BALANCE SUMMARY

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
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OCCIDENTAL SHALE OIL	.91650	90000.0	86.192	14441.92	84.328	
COLD TREATED WATER	1.00000	14418.4	13.808	2524.45	14.741	
50# STRIPPING STEAM				159.45	.931	

TOTAL CHARGE		104418.4	100.000	17125.81	100.000	
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PRODUCTS	SP. GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
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AV TURBINE FUEL JP-4	.78135	82581.8	79.089	11297.75	65.969	
SULFUR				87.79	.513	
ANHYDRUS AMMONIA				275.84	1.611	

TOTAL PRODUCTS SOLD		82581.8	79.089	11661.37	68.092	
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STREAMS CONVERTED TO UTILITIES	SP. GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
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F.O. STAB BOTTOMS	.86400	13159.9	12.603	1990.75	11.624	
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TOTAL STREAMS CONVERTED		13159.9	12.603	1990.75	11.624	
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STREAMS NOT UTILIZED	SP. GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
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LOSS				27.02	.159	
SULFUR PLANT LOSS				10.43	.061	
CO2--HYD. PLT.				647.65	3.782	
TREATED SOUR WATER	1.00000	15927.1	15.253	2788.60	16.283	

TOTAL NOT UTILIZED		15927.1	15.253	3473.69	20.283	
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TOTAL PRODUCTS MADE		111670.7	106.945	17125.81	100.000	
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USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

UNIT	CAPACITY CATEGORY	PLANT CAPACITY SUMMARY INVESTMENT CAPACITY UNITS/DAY				ACTUAL	INVESTMENT
		MAXIMUM	MINIMUM	FIXED	LP INPUT		
FEED PREPARATION	CAPACITY BBL/S/CD				90000.0	90004.9	9030000
L.P. HYDROTREATING	CAPACITY BBL/S/CD				90000.0	90004.9	59430000
H.P. HYDROTREATING	CAPACITY BBL/S/CD				92630.0	92635.6	96390000
HYDROCRACKING	CAPACITY BBL/S/CD				84600.6	84600.6	168517609
NAPHTHA SPLITTER	CAPACITY BBL/S/CD				24851.3	24851.3	2335209
DEBUTANIZER	CAPACITY BBL/S/CD				17916.8	17916.8	4088542
FUEL GAS TREATER	CAPACITY TONS/CD				1335.4	1335.4	1647258
SULFUR PLANT	CAPACITY TONS/CD				98.2	98.2	5876921
HYDROGEN PLANT	CAPACITY TONS/CD				737.3	737.3	124747396
SOUR WATER TREATING	CAPACITY BBL/S/CD				17624.7	17624.7	9708468
AMINE REGENERATION	CAPACITY TONS/CD				98.2	98.2	2728900
ATTOMIA PLANT	CAPACITY TONS/CD				275.8	275.8	433687
FUEL OIL STABILIZER	CAPACITY BBL/S/CD				13824.1	13824.1	3055945
COMBINED FACILITIES	CAPACITY BBL/S/CD				90000.0	90004.9	10815000
TOTAL OPTIMIZED INVESTMENT							498804934

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

## PRODUCT BLENDING

AV TURBINE FUEL JP-4	BBL/D	TONS/D	SPGR360F	WT% SULF	VL% AROM	SMOKE PT	FREEZ PT	D+L 293F	D+L 374F	D+L 473F
HC KEROSENE: 300-520F	65556.5	9207.64	.8022	.0003	9.4000	27.0000	-58.0000	2.5000	38.0000	88.0000
SPLITTER BOTTOMS	6390.3	852.56	.7620	.0003	7.0000	35.0000	-120.0000	98.0000	110.0000	100.0000
LT NAPHTHA JP-4	10637.0	1237.55	.6645	.0003	2.0000	35.0000	-160.0000	120.0000	120.0000	110.0000
BLEND	82583.8	11297.75	.7814	.0003	7.9400	28.4000	-75.9353	25.0240	54.1331	91.7622
SPECIFICATIONS		MAX MIN	.8017 .7507	.4000	25.0000	20.0000	-72.0000	20.0000	50.0000	90.0000

## PRODUCT BLENDING

AV TURBINE FUEL JP-4	BBL/D	TONS/D	D+L 518F
HC KEROSENE: 300-520F	65556.5	9207.64	100.0000
SPLITTER BOTTOMS	6390.3	852.56	100.0000
LT NAPHTHA JP-4	10637.0	1237.55	100.0000
BLEND	82583.8	11297.75	100.0000
SPECIFICATIONS		MAX MIN	100.0000

## PRODUCT BLENDING

SULFUR	BBL/D	TONS/D	SPGR360F
SULFUR		87.79	
BLEND		87.79	

NO SPECIFICATIONS

## PRODUCT BLENDING

ANHYDROUS ANTHRA	BBL/D	TONS/D	SPGR360F
ANHYDROUS ANTHRA		275.84	
BLEND		275.84	

NO SPECIFICATIONS

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 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

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BLEND FOR UTILITY PRODUCTION

REFINERY FUELS	BBL/D	TONS/D	SPGR260F
F.O. STAB BOTTOMS	13159.9	1990.75	.8640
BLEND	13159.9	1990.75	.8640
NO SPECIFICATIONS			

Appendix B.5 (Cont.)

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE  
 FEED PREPARATION  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LVZ	TONS/D	WTZ	MSCFD
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
DEASHED SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

DETAILED MATERIAL BALANCE  
 L.P. HYDROTREATING  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LVZ	TONS/D	WTZ	MSCFD
DEASHED SHALE OIL	.9165	90000.0	97.09	14441.92	95.66	
HYDROGEN (97Z)				182.55	1.21	54852.12
COLD TREATED WATER	1.0000	2700.6	2.91	472.83	3.13	
CHARGE		92700.6	100.00	15097.29	100.00	

PRODUCTS	SP. GR.	BSL/D	LVZ	TONS/D	WTZ	MSCFD
SOUR WATER - L.P.H.T	1.0000	3558.4	3.84	623.02	4.13	
HYDROGEN SULFIDE				79.57	.53	
SEPARATOR LIQUID(LP)	.8873	92629.0	99.92	14390.21	95.32	1772.18
LOSS				4.48	.03	
PRODUCTS		96187.4	103.76	15097.29	100.00	

DETAILED MATERIAL BALANCE  
 H.P. HYDROTREATING  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LVZ	TONS/D	WTZ	MSCFD
SEPARATOR LIQUID(LP)	.8873	92629.0	90.91	14390.21	88.14	
HYDROGEN (97Z)				277.30	1.70	86362.21
COLD TREATED WATER	1.0000	9263.6	9.09	1621.92	9.96	
CHARGE		101892.6	100.00	16289.43	100.00	

PRODUCTS	SP. GR.	BSL/D	LVZ	TONS/D	WTZ	MSCFD
SOUR WATER - H.P.H.T	1.0000	10535.1	10.34	1844.54	11.32	
SEPARATOR LIQUID(H.P.)	.8377	98425.5	96.60	14435.97	89.62	
LOSS				8.92	.05	
PRODUCTS		108960.6	106.94	16289.43	100.00	

USAF SHALE OIL TO FUELS

PHASE IV

CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE  
HYDROCRACKING  
COMPOSITE YIELDS

CHARGE	SP. GR.	88L/D	LV%	TONS/D	WT%	MSCFD
SEPARATOR LIQUID (HP)	.8377	84601.3	97.18	12408.39	93.47	
HYDROGEN (97%)				277.45	2.09	86409.58
COLD TREATED WATER	1.0000	2454.2	2.82	429.70	3.24	
50% STRIPPING STEAM				159.45	1.20	
CHARGE		87055.5	100.00	13274.99	100.00	
PRODUCTS						
LP FLASH GAS (JP-4)				613.10	4.62	29028.66
PROD FRACT OV'D: JP-4	.6536	24850.2	28.55	2843.75	21.42	
SOUR WATER (HC)	1.0000	3440.8	3.95	602.43	4.54	
HC KEROSENE: 300-520F	.8022	45556.5	75.30	9207.64	69.36	
LOSS				8.07	.06	
PRODUCTS		93847.5	107.80	13274.99	100.00	

DETAILED MATERIAL BALANCE  
NAPHTHA SPLITTER  
COMPOSITE YIELDS

CHARGE	SP. GR.	88L/D	LV%	TONS/D	WT%	MSCFD
PROD FRACT OV'D: JP-4	.6536	24850.2	100.00	2843.75	100.00	
CHARGE		24950.2	100.00	2843.75	100.00	
PRODUCTS						
SPLITTER GAS: JP-4	.6204	17915.8	72.10	45.13	1.59	918.37
SPLIT OV LIQ: JP-4	.7620	6390.3	25.72	1946.07	68.43	
SPLITTER BOTTOMS				852.56	29.98	
PRODUCTS		24306.1	97.81	2843.75	100.00	

USAF SHALE OIL TO FUELS  
PHASE IV  
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE  
DEBUTANIZER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
SPLIT OV LIQ:JP-4	.6204	17915.8	100.00	1946.07	100.00	
CHARGE		17915.8	100.00	1946.07	100.00	
PRODUCTS						
DEBUT OVER'D=JP-4	.5464	6693.0	37.36	640.29	32.90	9451.01
LT NAPHTHA JP-4	.6645	11223.3	62.64	1305.77	67.10	
PRODUCTS		17916.3	100.00	1946.07	100.00	

DETAILED MATERIAL BALANCE  
FUEL GAS TREATER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
LP FLASH GAS:JP-4)				613.10	45.91	29028.66
DEBUT OVER'D=JP-4	.5464	6693.0	100.00	640.29	47.95	9451.01
SPLITTER GAS:JP-4				45.13	3.38	915.37
F.O. STAB OVER'D				36.84	2.76	2018.90
CHARGE		6693.0	100.00	1335.36	100.00	

## PRODUCTS

HYDROGEN SULFIDE  
TRT LP FLASH:JP-4  
TRT DEB OV'D=JP-4  
TRT SPLIT GAS:JP-4  
TRT F.O. STAB OV'D

HYDROGEN SULFIDE	18.65	1.40	415.25
TRT LP FLASH:JP-4	603.04	45.16	28904.15
TRT DEB OV'D=JP-4	635.17	47.57	9337.27
TRT SPLIT GAS:JP-4	44.28	3.32	896.15
TRT F.O. STAB OV'D	34.23	2.56	1960.49
PRODUCTS	1335.36	100.00	

DETAILED MATERIAL BALANCE  
SULFUR PLANT  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
HYDROGEN SULFIDE				98.22	100.00	2187.43
CHARGE				98.22	100.00	
PRODUCTS						
SULFUR				67.79	69.38	
SULFUR PLANT LOSS				10.43	10.62	
PRODUCTS				98.22	100.00	

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE  
 HYDROGEN PLANT  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	HSCFD
TRT LP FLASH: JP-4				603.04	43.54	28804.15
TRT DEB OV'D=JP-4				635.17	45.86	9337.27
TRT SPLIT GAS=JP-4				44.28	3.20	896.15
TRT F.O. STAB OV'D				34.23	2.47	1960.49
LT NAPHTHA JP-4	.6645	586.4	100.00	68.22	4.93	
CHARGE		586.4	100.00	1384.94	100.00	
PRODUCTS						
HYDROGEN (97%)				737.30	53.24	229623.91
CO2--HYD. PLT.				647.65	46.76	
PRODUCTS				1384.94	100.00	

DETAILED MATERIAL BALANCE  
 SOUR WATER TREATING  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	HSCFD
SOUR WATER - L.P. HT	1.0000	3558.4	20.29	623.02	20.29	
SOUR WATER - H.P. HT	1.0000	10535.1	60.08	1844.54	60.08	
SOUR WATER (WC)	1.0000	3440.8	19.62	602.43	19.62	
CHARGE		17534.2	100.00	3069.99	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	15843.6	90.36	2773.98	90.36	
AMMONIA				290.46	9.46	
LOSS				5.55	.18	
PRODUCTS		15843.6	90.36	3069.99	100.00	

DETAILED MATERIAL BALANCE  
 AMINE REGENERATION  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	HSCFD
HYDROGEN SULFIDE				98.22	100.00	2187.43
CHARGE				98.22	100.00	
PRODUCTS						
HYDROGEN SULFIDE				98.22	100.00	2187.43
PRODUCTS				98.22	100.00	

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED MATERIAL BALANCE  
ANTONIA PLANT  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	MT%	MSCFD
ANTONIA						
CHARGE				290.46	100.00	
				290.46	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	83.5		14.62	5.03	
ANHYDRUS ANTONIA				275.84	94.97	
PRODUCTS		83.5		290.46	100.00	

DETAILED MATERIAL BALANCE  
FUEL OIL STABILIZER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	MT%	MSCFD
SEPARATOR LIQUID(HP)	.8377	13824.2	100.00	2027.59	100.00	
CHARGE		13824.2	100.00	2027.59	100.00	
PRODUCTS						
F.O. STAB OVER'D	.8640	13159.9	95.19	36.84	1.82	2018.90
F.O. STAB BOTTOMS				1990.75	98.18	
PRODUCTS		13159.9	95.19	2027.59	100.00	

DETAILED MATERIAL BALANCE  
COMBINED FACILITIES  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	MT%	MSCFD
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

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USAF SHALE OIL TO FUELS

Phase IV

CASE 1 - MAXIMUM JP-4 JET FUEL

		DETAILED USAGE OF AN UNPOOLED UTILITY		PRICE IS .04500/UNIT					
		ELECTRIC POWER UNIT IS KWH							
		COSTS ARE ALLOCATED TO PROCESS UNITS							
PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D	
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1080	.673	9720.85	437.44	
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	1.9070	11.884	171627.72	7723.25	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	1.2677	8.160	117422.70	5284.02	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	7.0969	48.387	600404.58	27018.21	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75	.3911	3.418	9719.95	437.40	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.6	1946.07	.1399	1.288	2506.53	112.79	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36					
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22		21.974	2158.30	97.12	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		235.698	173779.45	7820.08	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99	.3787	2.163	6640.41	298.82	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		40.773	4004.76	180.21	
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84		3.393	935.86	42.11	
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59	.1638	1.116	2263.80	101.87	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92					
TOTALS							1301184.93	49551.32	

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
600# STEAM UNIT IS HLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0193	.120	1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0158	.102	1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12409.39	.0075	.051	636.55	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22	.220		21.58	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30	-5.197		-3831.71	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22				
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							21.50	
AMOUNT PRODUCED FROM REFINERY FUELS							4564.99	3112.49
AMOUNT CONVERTED TO 150# STEAM							6011.71	
AMOUNT CONVERTED TO 50# STEAM							509.76	

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY  
 COOLING WATER UNIT IS MGAL PRICE IS .03000/UNIT  
 COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBU/D	TONS/D	UNIT/BBU	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0016	.010	145.06	4.38
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	.0398	.271	3365.15	100.95
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75	.0299	.261	742.22	22.27
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07	.0116	.106	207.26	6.22
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		99.22				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		.829	611.33	18.34
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99	.1336	.763	2342.76	70.28
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		32.389	3181.27	95.44
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84		10.961	3023.44	90.70
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59	.0200	.137	277.17	8.32
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							13896.47	416.89

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
 REFINERY FUELS UNIT IS MBTU  
 COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	9/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0218	.136	1961.21	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0482	.310	4466.72	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	.1729	1.179	16625.76	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75	.0640	.559	1591.08	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.6	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		57.519	42408.30	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22				
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59	.0486	.331	672.15	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							65725.22	
AMOUNT PRODUCED FROM F.O. STAB BOTTOMS							69878.21	
AMOUNT CONVERTED TO 600# STEAM							4189.99	

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
 150# STEAM UNIT IS MILBS  
 COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14190.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22		-7.593	-745.80	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99	.2633	1.504	4616.45	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		1.660	163.07	
ATFONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				

TOTALS

4033.71

AMOUNT PRODUCED FROM 600# STEAM

4033.71

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USAF SHALE OIL TO FUELS  
PHASE IV  
CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
50% STEAM  
UNIT IS MLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BSL/D	TONS/D	UNIT/BSL	UNIT/TON	UNITS/D	Q/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	-0.0031	-0.021	-261.82	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.6	1946.07	.0460	.424	824.35	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		99.22		-9.864	-968.82	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		9.327	916.07	
AMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							509.78	
AMOUNT PRODUCED FROM 600% STEAM							509.78	

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USAF SHALE OIL TO FUELS

PHASE IV

CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
BOILER WATER UNIT IS HLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12406.39	.0112	.076	946.76	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24650.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		53.22				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		18.946	1860.89	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99		16.887	12450.88	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22				
ANTHRA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							15258.54	
AMOUNT PURCHASED							4839.81	2419.91
AMOUNT PRODUCED FROM CONDENSATE							10418.72	

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
CONDENSATE UNIT IS MLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	-0.0193	-0.120	-1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	-0.0158	-0.102	-1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.3	12408.39	-0.0075	-0.051	-636.55	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24650.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.8	1946.07	-0.0460	-0.424	-824.35	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22		-0.684	-67.14	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3059.99	-0.2633	-1.504	-4616.45	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		-10.987	-1079.15	
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							-10418.72	
AMOUNT CONVERTED TO BOILER WATER							10418.72	

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 1 - MAXIMUM JP-4 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY  
CAT. & CHEMICALS UNIT IS \$  
PRICE IS 1.00000/UNIT  
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1145	.714	10308.64	10308.64
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0417	.268	3658.02	3658.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84601.1	12408.39	.0731	.488	6180.62	6180.62
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	24850.2	2843.75				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	17915.6	1946.07				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1335.36				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.22				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		737.30		5.004	3689.72	3689.72
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17534.2	3069.99				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.22		.283	27.76	27.76
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.84				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13824.2	2027.59				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							24064.75	24064.75

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 1 - MAXIMUM JP-4 JET FUEL

## PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	ELECTRIC POWER KWH	600# STE AM MLBS	COOLING WATER MGAL	REFINERY FUELS MMBTU	150# STE AM MLBS	50# STE AM MLBS	BOILER W ATER MLBS	CONDENSA TE MLBS
FEED PREPARATION	9720.9							
L.P. HYDROTREATING	171627.7	1733.0	145.9	1961.2				-1733.0
H.P. HYDROTREATING	117422.7	1462.0		4466.7				-1462.0
HYDROCRACKING	600404.6	636.6	3365.2	14625.8		-261.8	966.8	-636.6
NAPHTHA SPLITTER	9720.0		742.2	1591.1				
DEBUTANIZER	2506.5		207.3					
SULFUR PLANT	2158.3	21.6				824.4		-824.4
HYDROGEN PLANT	173779.5	-3831.7			-745.6	-968.6	1860.9	-67.1
SOUR WATER TREATING	6640.4		611.3	42408.3			12450.2	
AMINE REGENERATION	4004.8		2342.8		4616.4			-4616.4
AMMONIA PLANT	935.9		3181.3		163.1	916.1		-1079.2
FUEL OIL STABILIZER	2263.8		3023.4	672.1				
			277.2					
TOTAL CONSUMPTION	1101184.9	21.5	13696.5	65725.2	4033.7	509.8	15258.5	-10418.7

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## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 1 - MAXIMUM JP-4 JET FUEL

## PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	CAT. & C HEMICALS
FEED PREPARATION	
L.P. HYDROTREATING	10308.6
H.P. HYDROTREATING	3859.0
HYDROCRACKING	6180.6
NAPHTHA SPLITTER	
DEBUTANIZER	
SULFUR PLANT	3689.7
HYDROGEN PLANT	
SOUR WATER TREATING	27.6
AMINE REGENERATION	
ANTONIA PLANT	
FUEL OIL STABILIZER	
TOTAL CONSUMPTION	24064.7

Appendix B.6

JP-4 PLUS DIESEL CASE -- STANDARD OPTIMIZATION REPORT

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, PS1.0

USAF SHALE OIL TO FUELS  
PHASE IV

CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

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GROSS MARGIN SUMMARY

SALES	MARKET	PRODUCT	MAXIMUM	QUANTITY LIMITS MINIMUM	FIXED	QUANTITY SOLD	PRICE	TOTAL \$/DAY
A		AV TURBINE FUEL JP-4				48559.06 BBL	58.8200	2856240.96
A		DF-2/DF-M DIESEL				33184.22 BBL	58.8200	1951895.82
A		SULFUR				87.76 TON	95.4500	8376.31
A		ANHYDRUS AMMONIA				275.43 TON	155.0000	42691.06
TOTAL SALES REVENUE								4834254.15

RAW MATERIAL PURCHASED	MATERIAL	QUANTITY LIMITS	QUANTITY PURCHASED	PRICE	TOTAL
	OCCIDENTAL SHALE OIL	90000.0	90000.00 BBL	40.0000	3600000.00
	COLD TREATED WATER		14342.57 BBL	.0245	351.39
	50W STRIPPING STEAM		154.52 TON	.0000	.00
TOTAL RAW MATERIAL COST					3600351.39

GROSS MARGIN

1258902.76

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

## OPERATING COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	QUANTITY TON/D	\$/BBL	OPERATING COST \$/TON	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.029556	.18419	2660.05
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.294147	1.83308	26473.23
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.238964	1.53820	22134.96
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	81987.1	12024.97	.618072	4.21406	50673.94
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	11443.6	1292.32	.083930	.74321	960.46
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	8380.3	901.49	.113850	1.05835	954.09
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		778.09		.91020	708.21
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.18		19.67483	1931.73
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		421.42		41.68431	18409.54
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17427.9	3051.37	.208795	1.19253	3638.86
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.18		17.81405	1749.04
ANTONIA PLANT	COMBINED MODES	COMPOSITE COST		275.43		2.68881	740.57
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	16438.4	2411.00	.067122	.45764	1101.38
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE COST	90000.0	285.42		162.49114	46377.54
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST		14441.92	.098029	.61090	8822.57
TOTAL PROCESS UNIT OPERATING COST							187338.18
UTILITY PURCHASES	UTILITY	UNIT	\$/UNIT	UNITS/D	\$/D		
	BOILER WATER	MLBS	50000	6310.09	3155.05		
TOTAL UTILITY PURCHASES							3155.05
UTILITY SALES	UTILITY	UNIT	\$/UNIT	UNITS/D	\$/D		
	600# STEAM	MLBS	.00010	422.80	.04		
	50# STEAM	MLBS	.00010	623.15	.06		
TOTAL UTILITY SALES							.10
TOTAL OPERATING COST							190491.12

CAPITAL COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QUANTITY		CAPITAL COST	
			BBL/D	TON/D	\$/BBL	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.096215	8659.18
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.633231	56990.78
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.997898	92434.31
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	81987.1	12024.97	1.926602	157956.60
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	11443.6	1292.32	.132750	1519.60
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	8380.3	901.49	.319962	2681.37
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		778.09	1.54961	1205.73
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.18	57.38256	5633.99
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		421.42	178.92713	75403.88
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17427.9	3051.37	.532233	9275.71
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.18	26.64666	2616.25
ANTONIA PLANT	COMBINED MODES	COMPOSITE COST		275.43	1.50877	415.56
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	16438.4	2411.00	.194388	3195.43
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE COST		285.42	383.49301	109454.97
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.115235	10371.11
TOTAL						537814.67

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## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

## MATERIAL BALANCE SUMMARY

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
OCCIDENTAL SHALE OIL	.91650	90000.0	86.254	14441.92	84.418	
COLD TREATED WATER	1.00000	14142.6	13.746	2511.17	14.679	
50# STRIPPING STEAM				154.52	.903	
TOTAL CHARGE		104342.6	100.000	17107.61	100.000	

PRODUCTS	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
AV TURBINE FUEL JP-4	.78543	48559.9	46.539	6677.79	39.034	
DF-2/DF-M DIESEL	.83290	31184.2	31.803	4839.21	28.287	
SULFUR				87.76	.513	
ANHYDROUS AMMONIA				275.43	1.610	
TOTAL PRODUCTS SOLD		81744.1	78.342	11890.18	69.444	

STREAMS CONVERTED TO UTILITIES	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
F.O. STAB BOTTOMS	.86400	9433.5	9.041	1427.04	8.342	
TOTAL STREAMS CONVERTED		9433.5	9.041	1427.04	8.342	

STREAMS NOT UTILIZED	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
LOSS				26.76	.156	
SULFUR PLANT LOSS				10.43	.061	
CO2-HYD. PLT.				338.05	1.976	
TREATED SOUR WATER	1.00000	15823.2	15.165	2770.40	16.194	
PARTIAL OXIDAT.-LOSS				654.74	3.827	
TOTAL NOT UTILIZED		15823.2	15.165	3800.39	22.215	

TOTAL PRODUCTS MADE		107000.7	102.548	17107.61	100.000	
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## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

## PLANT CAPACITY SUMMARY INVESTMENT CAPACITY UNITS/DAY

UNIT	CAPACITY CATEGORY	MAXIMUM	MINIMUM	FIXED	LP INPUT	ACTUAL	INVESTMENT
FEED PREPARATION	CAPACITY BBL/CD				90000.0	90004.9	9030000
L.P. HYDROTREATING	CAPACITY BBL/CD				90000.0	90004.9	59430000
H.P. HYDROTREATING	CAPACITY BBL/CD				92630.0	92635.6	96390000
HYDROCRACKING	CAPACITY BBL/CD				81986.5	81986.5	164726166
NAPHTHA SPLITTER	CAPACITY BBL/CD				11444.7	11444.7	1584723
DEBUTANIZER	CAPACITY BBL/CD				8180.8	8180.8	2796286
FUEL GAS TREATER	CAPACITY TONS/CD				778.1	778.1	1257405
SULFUR PLANT	CAPACITY TONS/CD				98.2	98.2	5875452
HYDROGEN PLANT	CAPACITY TONS/CD				421.4	421.4	78635478
SOUR WATER TREATING	CAPACITY BBL/CD				17518.3	17518.3	9673242
AMINE REGENERATION	CAPACITY TONS/CD				98.2	98.2	2728375
AMMONIA PLANT	CAPACITY TONS/CD				275.4	275.4	433165
FUEL OIL STABILIZER	CAPACITY BBL/CD				16438.2	16438.2	3332381
PARTIAL OXIDATION	CAPACITY TONS/CD				285.4	285.4	114145891
COMBINED FACILITIES	CAPACITY BBL/CD				90000.0	90004.9	10815000
TOTAL OPTIMIZED INVESTMENT							560853766

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

## PRODUCT BLENDING

AV TURBINE FUEL JP-4	BBL/D	TONS/D	SPGR360F	WT% SULF	VL% ARCH	SPOKE PT	FREEZ PT	D+L 293F	D+L 374F	D+L 473F
HC KEROSENE: 300-520F	40776.0	5727.13	.8022	.0003	9.0000	27.0000	-58.0000	2.5000	38.0000	88.0000
SPLITTER BOTTOMS	2742.7	365.92	.7620	.0003	7.0000	35.0000	-120.0000	98.0000	110.0000	100.0000
LT NAPHTHA JP-4 DM	5041.1	584.74	.6825	.0003	2.0000	35.0000	-160.0000	120.0000	120.0000	110.0000
BLEND	48559.9	6677.79	.7854	.0003	8.1600	28.2200	-72.0907	20.0919	50.5793	90.9617
SPECIFICATIONS		MAX	.8017	.4000	25.0000		-72.0000			
		MIN	.7507			20.0000		20.0000	50.0000	90.0000

## PRODUCT BLENDING

AV TURBINE FUEL JP-4	BBL/D	TONS/D	D+L 518F
HC KEROSENE: 300-520F	40776.0	5727.13	100.0000
SPLITTER BOTTOMS	2742.7	365.92	100.0000
LT NAPHTHA JP-4 DM	5041.1	584.74	100.0000
BLEND	48559.9	6677.79	100.0000
SPECIFICATIONS		MAX	100.0000
		MIN	

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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USAF SHALE CIL TO FUELS  
PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

## PRODUCT BLENDING

DF-2/DF-M DIESEL	BBL/D	TONS/D	SPGR360F	WT% SULF	FLASH PT	CETANE I	D+L 700F	VIS 100F	POUR PT.	CLOUD PT
HC DIESEL:520-700F	33184.2	4839.21	.8329	.0003	268.0000	56.0000	100.0000	18.2400	.0000	5.0000
BLEN0	33184.2	4839.21	.8329	.0003	268.0000	56.0000	100.0000	18.2400	.0000	5.0000
SPECIFICATIONS		MAX	.8607	.7000			100.0000	18.4100	.0000	5.0000
		MIN	.8203		133.0000	45.0000		10.1100		

## PRODUCT BLENDING

DF-2/DF-M DIESEL	BBL/D	TONS/D	D+L 675F	D+L 725F
HC DIESEL:520-700F	33184.2	4839.21	90.0000	100.0000
BLEN0	33184.2	4839.21	90.0000	100.0000
SPECIFICATIONS		MAX	100.0000	
		MIN	90.0000	

## PRODUCT BLENDING

SULFUR	BBL/D	TONS/D	SPGR360F
SULFUR		87.76	
BLEN0		87.76	
NO SPECIFICATIONS			

## PRODUCT BLENDING

ANHYDRUS ANTONIA	BBL/D	TONS/D	SPGR360F
ANHYDRUS ANTONIA		275.43	
BLEN0		275.43	
NO SPECIFICATIONS			

## BLEND FOR UTILITY PRODUCTION

REFINERY FUELS	BBL/D	TONS/D	SPGR360F
F.O. STAB BOTTOMS	9433.5	1427.04	.8640
BLEN0	9433.5	1427.04	.8640
NO SPECIFICATIONS			

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USAF SHALE OIL TO FUELS

PHASE IV

CASE 2 - JP-4 JET FUEL + DF-2/DFH DIESEL

DETAILED MATERIAL BALANCE  
FEED PREPARATION  
COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LV%	TONS/D	WT%	HSCFD
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
( CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
DEASHED SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

DETAILED MATERIAL BALANCE  
L.P. HYDROTREATING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LV%	TONS/D	WT%	HSCFD
DEASHED SHALE OIL	.9165	90000.0	97.09	14441.92	95.66	
HYDROGEN (97%)				182.55	1.21	56852.12
COLD TREATED WATER	1.0000	2700.6	2.91	472.83	3.13	
CHARGE		92700.6	100.00	15097.29	100.00	
PRODUCTS						
SOUR WATER - L.P.H.T	1.0000	3558.4	3.84	623.02	4.13	
HYDROGEN SULFIDE				79.57	.53	
SEPARATOR LIQUID(LP)	.8873	92629.0	99.92	14390.21	95.32	1772.18
LOSS				4.48	.03	
PRODUCTS		96187.4	103.76	15097.29	100.00	

DETAILED MATERIAL BALANCE  
H.P. HYDROTREATING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LV%	TONS/D	WT%	HSCFD
SEPARATOR LIQUID(LP)	.8873	92629.0	90.91	14390.21	88.34	
HYDROGEN (97%)				277.30	1.70	86362.21
COLD TREATED WATER	1.0000	9263.6	9.09	1621.92	9.96	
CHARGE		101892.6	100.00	16289.43	100.00	
PRODUCTS						
SOUR WATER - H.P.H.T	1.0000	10535.1	10.34	1844.54	11.32	
SEPARATOR LIQUID(H.P)	.8377	98425.5	96.60	14435.97	88.62	
LOSS				8.92	.05	
PRODUCTS		108960.6	106.94	16289.43	100.00	

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

USAF SHALE OIL TO FUELS  
PHASE IV

CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
HYDROCRACKING  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
SEPARATOR LIQUID (HP)	.8377	81987.1	97.18	12024.97	93.63	
HYDROGEN (97%)				246.99	1.92	76923.54
COLD TREATED WATER	1.0000	2378.4	2.82	416.42	3.24	
50# STRIPPING STEAM				154.52	1.20	
CHARGE		84365.5	100.00	12842.91	100.00	

## PRODUCTS

LP FLASH GAS: JP-4-DH  
PROD FRACT OV: JP4-DH  
SOUR WATER (HC)  
HC KEROSENE: 300-520F  
HC DIESEL: 520-700F  
LOSS

PRODUCTS	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
LP FLASH GAS: JP-4-DH	.6450	11443.6	13.56	392.62	3.06	24226.60
PROD FRACT OV: JP4-DH	1.0000	3334.4	3.95	1292.32	10.06	
SOUR WATER (HC)	.8022	40776.0	48.33	583.81	4.55	
HC KEROSENE: 300-520F	.8329	33184.2	39.33	5727.13	44.59	
HC DIESEL: 520-700F				4839.21	37.68	
LOSS				7.82	.06	
PRODUCTS		88738.3	105.18	12842.91	100.00	

DETAILED MATERIAL BALANCE  
NAPHTHA SPLITTER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
PROD FRACT OV: JP4-DH	.6450	11443.6	100.00	1292.32	100.00	
CHARGE		11443.6	100.00	1292.32	100.00	
PRODUCTS						
SPLITTER GAS: JP4-DH	.6144	8380.3	73.23	24.92	1.93	580.80
SPLIT OV LIQ: JP4-DH	.7620	2742.7	23.97	901.49	69.76	
SPLITTER BOTTOMS				365.92	28.31	
PRODUCTS		11123.0	97.20	1292.32	100.00	

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## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, PSL.0

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
DEBUTANIZER  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	HSCFD
SPLIT OV LIQ=JP4-DH	.6144	8380.3	100.00	901.49	100.00	
CHARGE		8380.3	100.00	901.49	100.00	
PRODUCTS						
DEBUT OVER'D=JP4-DH	.5418	3339.0	39.84	316.75	35.14	4802.32
LT NAPHTHA JP-4 DH	.6625	5041.1	60.15	584.74	64.86	
PRODUCTS		8380.2	100.00	901.49	100.00	

DETAILED MATERIAL BALANCE  
FUEL GAS TREATER  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	HSCFD
LP FLASH GAS=JP-4-DH				392.62	50.46	24226.60
DEBUT OVER'D=JP4-DH	.5418	3339.0	100.00	316.75	40.71	4802.32
SPLITTER GAS=JP4-DH				24.92	3.20	580.80
F.O. STAB OVER'D				43.81	5.63	2400.68
CHARGE		3339.0	100.00	778.09	100.00	
PRODUCTS						
HYDROGEN SULFIDE				18.61	2.39	414.41
TRT LP FLASH=JP4-DH				382.92	49.21	23998.91
TRT DEB OV'D=JP4-DH				311.77	40.07	4691.31
TRT SPLIT GAS=JP4-DH				24.09	3.10	562.38
TRT F.O. STAB OV'D				40.70	5.23	2331.22
PRODUCTS				778.09	100.00	

DETAILED MATERIAL BALANCE  
SULFUR PLANT  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	HSCFD
HYDROGEN SULFIDE				98.18	100.00	2186.59
CHARGE				98.18	100.00	
PRODUCTS						
SULFUR				87.76	89.38	
SULFUR PLANT LOSS				10.43	10.62	
PRODUCTS				98.18	100.00	

USAF SHALE OIL TO FUELS  
PHASE IV  
CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
HYDROGEN PLANT  
COMPOSITE YIELDS

CHARGE	SP. GR.	BB/L/D	LV%	TONS/D	WT%	MSCFD
TRT LP FLASH: JP4-DH				382.92	50.42	23998.91
TRT DEB OV'D=JP4-DH				311.77	41.05	4691.31
TRT SPLIT GAS=JP4-DH				24.09	3.17	562.38
TRT F.O. STAB OV'D				40.70	5.36	2331.22
CHARGE				759.48	100.00	
PRODUCTS						
HYDROGEN (97%)				421.42	55.49	131247.89
CO2--HYD. PLT.				338.05	44.51	
PRODUCTS				759.48	100.00	

DETAILED MATERIAL BALANCE  
SOUR WATER TREATING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BB/L/D	LV%	TONS/D	WT%	MSCFD
SOUR WATER - L.P.HT	1.0000	3558.4	20.42	623.02	20.42	
SOUR WATER - H.P.HT	1.0000	10535.1	60.45	1844.54	60.45	
SOUR WATER (HC)	1.0000	3334.4	19.13	583.81	19.13	
CHARGE		17427.9	100.00	3051.37	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	15739.8	90.31	2755.81	90.31	
ANTHRA				290.02	9.50	
LOSS				5.54	.18	
PRODUCTS		15739.8	90.31	3051.37	100.00	

DETAILED MATERIAL BALANCE  
AMINE REGENERATION  
COMPOSITE YIELDS

CHARGE	SP. GR.	BB/L/D	LV%	TONS/D	WT%	MSCFD
HYDROGEN SULFIDE				98.18	100.00	2186.59
CHARGE				98.18	100.00	
PRODUCTS						
HYDROGEN SULFIDE				98.18	100.00	2186.59
PRODUCTS				98.18	100.00	

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USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 2 - JP-4 JET FUEL + DF-2/DFM DIE

DETAILED MATERIAL BALANCE  
 ANTONIA PLANT  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LV%	TONS/D	WT%	MSCFD
ANTONIA						
CHARGE						
PRODUCTS						
TREATED SOUR WATER	1.0000	83.4		14.60	5.03	
ANHYDROUS ANTONIA				275.43	94.97	
PRODUCTS		83.4		290.02	100.00	

DETAILED MATERIAL BALANCE  
 FUEL OIL STABILIZER  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LV%	TONS/D	WT%	MSCFD
SEPARATOR LIQUID (MP)	.8377	16438.4	100.00	2411.00	100.00	
CHARGE		16438.4	100.00	2411.00	100.00	
PRODUCTS						
F.O. STAB OVER'D	.8640	15648.4	95.19	43.81	1.82	2400.68
F.O. STAB BOTTOMS				2367.20	98.18	
PRODUCTS		15648.4	95.19	2411.00	100.00	

DETAILED MATERIAL BALANCE  
 PARTIAL OXIDATION  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LV%	TONS/D	WT%	MSCFD
F.O. STAB BOTTOMS	.8640	6215.0	100.00	940.16	100.00	
CHARGE		6215.0	100.00	940.16	100.00	
PRODUCTS						
HYDROGEN (97%)				285.42	30.36	88889.98
PARTIAL OXIDATION - LOSS				654.74	69.64	
PRODUCTS				940.16	100.00	

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USAF SHALE OIL TO FUELS

PHASE IV

CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
COMBINED FACILITIES  
COMPOSITE YIELDS

	SP. GR.	BSL/D	LVZ	TONS/D	WT%	MSCFD
CHARGE						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

USAF SHALE OIL TO FUELS

PHASE IV

CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY  
ELECTRIC POWER UNIT IS KWH  
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1080	.673	9720.85	437.44
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	1.9070	11.884	171627.72	7723.25
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	1.2677	8.160	117422.70	5284.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	6.1047	41.622	500503.29	22522.65
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32	.3912	3.464	4476.35	201.44
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49	.1399	1.301	1172.47	52.76
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		21.974	2157.47	97.09
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		238.910	100682.00	4510.69
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37	.3787	2.163	6600.30	297.01
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		40.773	4003.22	180.14
ATTORCIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43		1.391	934.47	42.05
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00	.1638	1.116	2691.89	121.13
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		2072.400	591495.71	26617.31
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							1513488.45	68106.98

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
600# STEAM UNIT IS MLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL	STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE	USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE	USAGE	90000.0	14441.92	.0193	.120	1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE	USAGE	92629.0	14390.21	.0158	.102	1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE	USAGE	81987.1	12024.97				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE	USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE	USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE	USAGE		778.09		.220	21.57	
SULFUR PLANT	COMBINED MODES	COMPOSITE	USAGE		98.18		-4.995	-2105.17	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE	USAGE		421.42				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE	USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE	USAGE		98.18				
AFONIXIA PLANT	COMBINED MODES	COMPOSITE	USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE	USAGE	16438.4	2411.00		-14.086	-4020.37	
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE	USAGE	90000.0	285.42				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE	USAGE		14441.92				
TOTALS								-2908.89	
AMOUNT SOLD								422.80	.04
AMOUNT CONVERTED TO 150# STEAM								2486.10	

Appendix B.6 (Cont.)

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY  
COOLING WATER UNIT IS MGAL  
COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0016	.010	145.86	4.38
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92627.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	.0263	.179	2152.47	64.57
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32	.0299	.264	341.82	10.25
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49	.0116	.107	96.91	2.91
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42	.1336	.869	366.13	10.98
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37		.763	2328.61	69.86
ARINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		32.389	3180.05	95.40
AMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43	.0200	10.961	3018.95	90.57
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00		.137	329.58	9.89
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		98.338	28067.22	842.02
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							40027.60	1200.83

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
REFINERY FUELS UNIT IS MBTU  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0218	.136	1961.21	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14350.21	.0482	.310	4466.72	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	.1721	1.171	14110.10	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32	.0640	.567	732.75	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		56.904	23980.61	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00	.0486	.331	799.25	
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		14.149	4038.35	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							50088.99	
AMOUNT PRODUCED FROM F.O. STAB BOTTOMS							50088.99	

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USAF SHALE OIL TO FUELS  
PHASE IV

CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
150# STEAM UNIT IS HLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BSL/O	TONS/O	UNIT/BSL	UNIT/TON	UNITS/O	\$/O
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	-0.0185	-0.126	-1519.96	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-7.593	-745.51	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37	.2633	1.504	4588.56	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		1.660	163.00	
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							2486.10	
AMOUNT PRODUCED FROM 600# STEAM							2486.10	

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
50# STEAM UNIT IS HLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	-.0117	-.079	-955.99	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49	.0460	.428	385.57	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-9.864	-968.45	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37		9.327	915.71	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							-623.15	
AMOUNT SOLD							623.15	.06

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
BOILER WATER UNIT IS HLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	¢/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	.0390	.266	3201.05	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		18.946	1860.18	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		16.550	6974.54	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
ANTHRA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		12.576	3589.39	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							15625.15	
AMOUNT PURCHASED							6310.09	3155.05
AMOUNT PRODUCED FROM CONDENSATE							9315.06	

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
CONDENSATE UNIT IS MLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	-.0193	-.120	-1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	-.0158	-.102	-1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8380.3	901.49	-.0460	-.428	-385.57	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-.684	-67.12	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18	-.2633	-1.504	-4588.56	
ATONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43		-10.987	-1078.74	
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							-9315.06	
AMOUNT CONVERTED TO BOILER WATER							9315.06	

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

## DETAILED USAGE OF AN UNPOOLED UTILITY

CAT. &amp; CHEMICALS UNIT IS \$ PRICE IS 1.00000/UNIT

COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1145	.714	10308.64	10308.64
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0417	.268	3858.02	3858.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	81987.1	12024.97	.0578	.394	4742.65	4742.65
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11443.6	1292.32				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	9380.3	901.49				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		778.09				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		421.42		4.979	2098.39	2098.39
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17427.9	3051.37		.283	27.75	27.75
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.43				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	16438.4	2411.00				
PARTIAL OXIDATION	COMBINED MODES	COMPOSITE USAGE		285.42		4.223	1205.31	1205.31
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
TOTALS							22240.75	22240.75

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

## PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	ELECTRIC POWER KWH	600# STE AM MLBS	COOLING WATER MGAL	REFINERY FUELS MMBTU	150# STE AM MLBS	50# STE AM MLBS	BOILER W ATER MLBS	CONDENSA TE MLBS
FEED PREPARATION	9720.9							
L.P. HYDROTREATING	171627.7	1733.0	145.9	1961.2				-1733.0
H.P. HYDROTREATING	117422.7	1462.0		4466.7				-1462.0
HYDROCRACKING	500503.3		2152.5	14110.1	-1520.0	-956.0	1201.0	
NAPHTHA SPLITTER	4476.4		341.8	732.7				
DEBUTANIZER	1172.5		96.9			385.6		-385.6
SULFUR PLANT	2157.5	21.6			-745.5	-968.4	1860.2	-67.1
HYDROGEN PLANT	100582.0	-2105.2	366.1	23980.6			6974.5	
SOUR WATER TREATING	6600.3		2328.6		4588.6			-4588.6
AMINE REGENERATION	4003.2		3180.1		163.0	915.7		-1078.7
ATYOKIA PLANT	934.5		3018.9					
FUEL OIL STABILIZER	2691.9		329.6	799.2				
PARTIAL OXIDATION	591495.7	-4020.4	28067.2	4038.3			3589.4	
TOTAL CONSUMPTION	1513468.5	-2908.9	40027.6	50089.0	2486.1	-623.2	15625.2	-9315.1

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USAF SHALE OIL TO FUELS

PHASE IV

CASE 2 - JP-4 JET FUEL + DF-2/DFM DIESEL

## PROCESS UNIT UTILITY CONSUMPTION SUMMARY

CAT. & C  
HENICALS

PROCESS UNIT

FEED PREPARATION	
L.P. HYDROTREATING	10308.6
H.P. HYDROTREATING	3858.0
HYDROCRACKING	4742.6
NAPHTHA SPLITTER	
DEBUTANIZER	
SULFUR PLANT	
HYDROGEN PLANT	2098.4
SOUR WATER TREATING	
AMINE REGENERATION	27.7
AMMONIA PLANT	
FUEL OIL STABILIZER	
PARTIAL OXIDATION	1205.3
TOTAL CONSUMPTION	22240.7

## MAXIMUM JP-8 CASE -- STANDARD OPTIMIZATION REPORT

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0  
 USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

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## GROSS MARGIN SUMMARY

SALES	MARKET	PRODUCT	MAXIMUM	QUANTITY LIMITS MINIMUM	FIXED	QUANTITY SOLD	PRICE	TOTAL \$/DAY
A		UNLEADED GASOLINE				7963.79 BBL	58.8000	468270.85
A		AV TURBINE FUEL JP-8				72667.97 BBL	58.8000	427276.64
A		SULFUR				87.77 TON	95.4500	8377.85
A		ANYTORUS ANYONIA				276.68 TON	155.0000	42885.11
TOTAL SALES REVENUE								4792410.45
RAW MATERIAL PURCHASED	MATERIAL	QUANTITY LIMITS	QUANTITY PURCHASED	PRICE	TOTAL			
	OCCIDENTAL SHALE OIL	90000.0	90000.00 BBL	40.0000	3600000.00			
	COLD TREATED WATER		14749.31 BBL	.0245	361.36			
	50# STRIPPING STEAM		169.56 TON	.0000	.00			
TOTAL RAW MATERIAL COST					360361.36			
GROSS MARGIN					1192049.09			

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

## OPERATING COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	QUANTITY TON/D	\$/BBL	OPERATING COST \$/TON	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.029556	.18419	2660.05
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.294147	1.83308	26473.23
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.238964	1.53820	22134.96
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	89866.8	13195.34	.677281	4.61775	60932.61
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	22993.1	2626.40	.054444	.47664	1251.84
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	16633.9	1804.78	.068802	.63412	1144.45
DEPROPANIZER	COMBINED MODES	COMPOSITE COST	1229.3	117.47	.532947	5.57700	655.14
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		1176.39		.61770	726.66
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		93.20		19.67483	1932.09
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		752.27		39.28601	29553.74
NAPHTHA HYDROTREAT	COMBINED MODES	COMPOSITE COST	5837.5	778.81	.295563	2.21537	1725.34
LOP PLATFORMING	COMBINED MODES	COMPOSITE COST	5837.6	778.42	.750106	5.62530	4378.83
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17827.7	3138.68	.204485	1.16792	3665.95
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.20		17.81405	1749.36
ATTOMIXA PLANT	COMBINED MODES	COMPOSITE COST		276.68		2.68881	743.93
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	8458.7	1240.63	.115919	.79034	980.52
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.098029	.51090	8822.57
UTILITY UNIT	COMBINED MODES	COMPOSITE COST	840.6	84.52			
TOTAL PROCESS UNIT OPERATING COST							169531.48
UTILITY PURCHASES	UTILITY	UNIT	UNITS/D	\$/UNIT		\$/D	
BOILER WATER		MLBS	5560.86	.50000			
TOTAL UTILITY PURCHASES							2780.43
UTILITY PRODUCTION COSTS	UTILITY	UNIT	UNITS/D			\$/D	
600# STEAM		MLBS	4151.38				
TOTAL UTILITY PRODUCTION COSTS							2830.48
TOTAL OPERATING COST							175142.40

Appendix B.7 (Cont.)

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

## CAPITAL COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	QUANTITY TON/D	\$/BBL	CAPITAL COST \$/TON	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.096215	.59960	8459.18
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.633231	3.94621	56990.78
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92639.0	14390.21	.997898	6.42342	92434.31
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	89666.8	13195.34	1.878017	12.80446	168959.22
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	22993.1	2626.40	.091678	.82011	2153.93
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	16633.9	1804.78	.227102	2.09310	3777.60
DEPROPANIZER	COMBINED MODES	COMPOSITE COST	1229.3	1176.39	.744536	7.79117	915.24
FUEL GAS TREATER	COMBINED MODES	COMPOSITE COST		98.20		1.26026	1482.56
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		752.27		57.37868	5634.67
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		778.81		161.67252	121621.61
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE COST	5837.5	778.81	.560212	4.19902	3270.22
LOP PLATFORMING	COMBINED MODES	COMPOSITE COST	5837.6	778.42	1.772736	13.29436	10348.56
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17927.7	3338.88	.526209	3.00544	9411.73
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.20		26.64422	2616.49
ATTOMIA PLANT	COMBINED MODES	COMPOSITE COST		276.68		1.50535	416.50
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	8458.7	1240.63	.270987	1.84761	2292.20
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.115235	.71813	10171.11
DUTTY UNIT	COMBINED MODES	COMPOSITE COST	840.6	84.52			

TOTAL

501378.11

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

## MATERIAL BALANCE SUMMARY

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
OCCIDENTAL SHALE OIL	.91650	90000.0	85.919	14441.92	83.995	
COLD TREATED WATER	1.00000	14749.3	14.081	2582.39	15.019	
SOW STRIPPING STEAM				169.56	.986	
TOTAL CHARGE		104749.3	100.000	17193.86	100.000	
PRODUCTS	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
UNLEADED GASOLINE	.74714	7963.8	7.603	1041.78	6.059	
AV TURBINE FUEL JP-8	.80500	72668.0	69.373	10242.09	59.568	
SULFUR				87.77	.510	
ANHYDRUS AMONIA				276.68	1.609	
TOTAL PRODUCTS SOLD		80631.8	76.976	11648.32	67.747	
STREAMS CONVERTED TO UTILITIES	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
F.O. STAB BOTTOMS	.86400	8052.2	7.687	1218.09	7.084	
LT NAPHTHA JP-8	.66430	6918.6	6.605	804.69	4.680	
TOTAL STREAMS CONVERTED		14970.8	14.292	2022.78	11.765	
STREAMS NOT UTILIZED	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
LOSS				27.54	.160	
SULFUR PLANT LOSS				10.43	.061	
CO2-HYD. PLT.				628.16	3.653	
TREATED SOUR WATER	1.00000	16315.7	15.576	2856.63	16.614	
TOTAL NOT UTILIZED		16315.7	15.576	3522.76	20.488	
TOTAL PRODUCTS MADE		111918.2	106.844	17193.86	100.000	

Appendix B.7 (Cont.)

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 3 - MAXIMUM JP-8 JET FUEL

## PLANT CAPACITY SUMMARY INVESTMENT CAPACITY UNITS/DAY

UNIT	CAPACITY CATEGORY	MAXIMUM	MINIMUM	FIXED	LP INPUT	ACTUAL	INVESTMENT
FEED PREPARATION	CAPACITY BBLS/CD				90000.0	90004.9	9030000
L.P. HYDROTREATING	CAPACITY BBLS/CD				90000.0	90004.9	59430000
H.P. HYDROTREATING	CAPACITY BBLS/CD				92630.0	92635.6	96390000
HYDROCRACKING	CAPACITY BBLS/CD				89966.1	89966.1	176200324
NAPHTHA SPLITTER	CAPACITY BBLS/CD				22993.9	22993.9	2246246
DEBUTANIZER	CAPACITY BBLS/CD				16634.3	16634.3	3939493
DEPROPANIZER	CAPACITY BBLS/CD				1229.2	1229.2	954469
FUEL GAS TREATER	CAPACITY TONS/CD				1176.4	1176.4	1546099
SULFUR PLANT	CAPACITY TONS/CD				98.2	98.2	5876153
HYDROGEN PLANT	CAPACITY TONS/CD				752.3	752.3	126833967
NAPHTHA HYDROTREATER	CAPACITY BBLS/CD				5937.5	5937.5	3410374
WOP PLATFORMING	CAPACITY BBLS/CD				5837.8	5837.8	10792066
SOUR WATER TREATING	CAPACITY BBLS/CD				18018.5	18018.5	9838031
AMINE REGENERATION	CAPACITY TONS/CD				98.2	98.2	2728426
ANTONIA PLANT	CAPACITY TONS/CD				276.7	276.7	434349
FUEL OIL STABILIZER	CAPACITY BBLS/CD				8458.6	8458.6	2390435
COMBINED FACILITIES	CAPACITY BBLS/CD				90000.0	90004.9	10815000
TOTAL OPTIMIZED INVESTMENT							522855633

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

## PRODUCT BLENDING

UNLEADED GASOLINE	BBL/D	TONS/D	SPGR@60F	WT% SULF	RES OCTN	HOT OCTN	(R+M)12	RVP INDX	VL% AROM	D+L 131F
LT NAPHTHA JP-8	2498.0	290.54	.6643	.0003	75.0000	73.0000	74.0000	175.0000	2.0000	51.0000
100 RON PLATFORMATE	4625.2	666.71	.8233	.0003	100.0000	88.6000	94.3000	55.1000	72.6000	1.0000
MIXED BUTANES	840.6	84.52	.5743	.0003	98.5000	94.3000	96.4000	1280.0000	.0000	100.0000
BLEND	7963.8	1041.78	.7471	.0003	92.0000	84.3084	88.1542	222.0000	42.7920	27.1330
SPECIFICATIONS		MAX		.1000	92.0000	82.0000	87.0000	222.0000	55.0000	10.0000
		MIN								

## PRODUCT BLENDING

UNLEADED GASOLINE	BBL/D	TONS/D	D+L 171F	D+L 235F	D+L 365F	D+L 437F
LT NAPHTHA JP-8	2498.0	290.54	96.0000	100.0000	100.0000	100.0000
100 RON PLATFORMATE	4625.2	666.71	7.0000	38.0000	100.0000	100.0000
MIXED BUTANES	840.6	84.52	100.0000	100.0000	100.0000	100.0000
BLEND	7963.8	1041.78	44.7327	63.9916	100.0000	100.0000
SPECIFICATIONS		MAX	50.0000	50.0000	90.0000	100.0000
		MIN				

Appendix B.7 (Cont.)

USAF SHALE OIL TO FUELS  
PHASE IV  
CASE 3 - MAXIMUM JP-8 JET FUEL

## PRODUCT BLENDING

AV TURBINE FUEL JP-8	BBL/D	TONS/D	SPGR360F	WT% SULF	VL% ARCH	SHOKE PT	FREEZ PT	VL% NAPH	FLASH PT	D+L 401F
HC KEROSENE: 300-550F	72668.0	10242.09	.8050	.0003	10.0000	26.0000	-58.0000	1.5000	100.0000	40.0000
BLEN	72668.0	10242.09	.8050	.0003	10.0000	26.0000	-58.0000	1.5000	100.0000	40.0000
SPECIFICATIONS		MAX MIN	.8398 .7753	.4000	25.0000	20.0000	-58.0000	3.0000	100.0000	10.0000

## PRODUCT BLENDING

AV TURBINE FUEL JP-8	BBL/D	TONS/D	D+L 572F
HC KEROSENE: 300-550F	72668.0	10242.09	100.0000
BLEN	72668.0	10242.09	100.0000

## SPECIFICATIONS

MAX	MIN
100.0000	

## Appendix B.7 (Cont.)

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## PRODUCT BLENDING

SULFUR	BBL/D	TONS/D	SPGR360F
SULFUR		87.77	
BLEN		87.77	

## NO SPECIFICATIONS

## PRODUCT BLENDING

ANHYDRUS ATTOMIA	BBL/D	TONS/D	SPGR360F
ANHYDRUS ATTOMIA		276.68	
BLEN		276.68	

## NO SPECIFICATIONS

## RECYCLE STREAM BLENDING

MIXED BUTANES	BBL/D	TONS/D	SPGR360F
MIXED C4'S: JP-8	840.6	84.52	.5743
BLEN	840.6	84.52	.5743

## NO SPECIFICATIONS

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USAF SHALE OIL TO FUELS

PHASE IV

CASE 3 - MAXIMUM JP-8 JET FUEL

BLEND FOR UTILITY PRODUCTION

REFINERY FUELS	BBL/D	TONS/D	SPGR260F
F.O. STAB BOTTOMS	8052.2	1218.09	.8640
LT NAPHTHA JP-8	6918.6	804.69	.6643
BLEND	14970.8	2022.78	.7717
NO SPECIFICATIONS			

Appendix B.7 (Cont.)

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE  
 FEED PREPARATION  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
DEASHED SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

DETAILED MATERIAL BALANCE  
 L.P. HYDROTREATING  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
DEASHED SHALE OIL	.9165	90000.0	97.09	14441.92	95.66	
HYDROGEN (97%)				182.55	1.21	56852.12
COLD TREATED WATER	1.0000	2700.6	2.91	472.83	3.13	
CHARGE		92700.6	100.00	15097.29	100.00	
PRODUCTS						
SOUR WATER - L.P.HT	1.0000	3558.4	3.84	623.02	4.13	
HYDROGEN SULFIDE				79.57	.53	1772.10
SEPARATOR LIQUID(LP)	.8873	92629.0	99.92	14390.21	95.32	
LOSS				4.48	.03	
PRODUCTS		96187.4	103.76	15097.29	100.00	

DETAILED MATERIAL BALANCE  
 H.P. HYDROTREATING  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
SEPARATOR LIQUID(LP)	.8873	92629.0	90.91	14390.21	88.14	
HYDROGEN (97%)				277.30	1.70	86362.21
COLD TREATED WATER	1.0000	9263.6	9.09	1621.92	9.96	
CHARGE		101892.6	100.00	16289.43	100.00	
PRODUCTS						
SOUR WATER - H.P.HT	1.0000	10535.1	10.34	1844.54	11.32	
SEPARATOR LIQUID(H.P.)	.8377	98425.5	96.60	14435.97	88.62	
LOSS				8.92	.05	
PRODUCTS		108960.6	106.94	16289.43	100.00	

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USAF SHALE OIL TO FUELS  
PHASE IV  
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE  
HYDROCRACKING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
SEPARATOR LIQUID (NP)	.8377	89966.8	97.18	13195.34	93.49	
HYDROGEN (97%)				291.88	2.07	90903.50
COLD TREATED WATER	1.0000	2609.9	2.82	456.95	3.24	
50% STRIPPING STEAM				169.56	1.20	

CHARGE

92576.7 100.00 14113.74 100.00

PRODUCTS

LP FLASH GAS: JP-8				596.03	4.22	29761.69
PROD FRACT OV: JP-8	.6524	22993.1	24.84	2626.40	18.61	
SOUR WATER (HC)	1.0000	3659.0	3.95	640.63	4.54	
HC KEROSENE: 100-550F	.8050	72668.0	78.49	10242.09	72.57	
LOSS				8.58	.06	

PRODUCTS

99320.0 107.28 14113.74 100.00

DETAILED MATERIAL BALANCE  
NAPHTHA SPLITTER  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
PROD FRACT OV: JP-8	.6524	22993.1	100.00	2626.40	100.00	
CHARGE		22993.1	100.00	2626.40	100.00	

PRODUCTS

SPLITTER GAS: JP-8				42.81	1.63	887.76
SPLIT OV LIQ: JP-8	.6197	16633.9	72.34	1804.78	68.72	
SPLITTER BOTTOMS	.7620	5837.5	25.39	778.81	29.65	
PRODUCTS		22471.4	97.73	2626.40	100.00	

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE  
DEBUTANIZER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
SPLIT OV LIQ=JP-8	.6197	16633.9	100.00	1804.78	100.00	
CHARGE		16633.9	100.00	1804.78	100.00	
PRODUCTS						
DEBUT OVER'D=JP-8	.5458	6263.9	37.66	598.59	33.17	8864.78
LT NAPHTHA JP-8	.6643	10370.6	62.35	1206.19	66.83	
PRODUCTS		16634.5	100.00	1804.78	100.00	

DETAILED MATERIAL BALANCE  
DEPHOPANIZER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
DEBUT OVER'D=JP-8	.5458	1229.3	100.00	117.47	100.00	1739.69
CHARGE		1229.3	100.00	117.47	100.00	
PRODUCTS						
DEPHOP OV'D JP-8	.5743	840.6	68.38	32.95	28.05	637.45
MIXED C4'S JP-8				84.52	71.95	
PRODUCTS		840.6	68.38	117.47	100.00	

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE  
 FUEL GAS TREATER  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	MSCFD
LP FLASH GAS: JP-8				596.03	50.67	29761.69
DEBUT OVER'D=JP-8				481.12	40.90	7125.09
SPLITTER GAS=JP-8	.5458	5034.7	100.00	42.81	3.64	887.76
DEPROP OV'D JP-8				32.95	2.80	617.45
NAP HYDROTREAT GAS				.93	.02	102.21
F.O. STAB OVER'D				22.54	1.92	1235.32
CHARGE		5034.7	100.00	1176.39	100.00	

PRODUCTS

HYDROGEN SULFIDE				18.63	1.58	414.81
TRT LP FLASH: JP-8				585.36	49.76	29520.27
TRT DEB OV'D=JP-8				476.74	40.53	7027.35
TRT SPLIT GAS=JP-8				41.90	3.56	867.76
TRT DEP OV'D-JP8				31.88	2.71	613.61
TRT NAP HRTT GAS				.93	.08	102.21
TRT F.O. STAB OV'D				20.94	1.78	1199.58
PRODUCTS				1176.39	100.00	

Appendix B.7 (Cont.)

DETAILED MATERIAL BALANCE  
 SULFUR PLANT  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	MSCFD
HYDROGEN SULFIDE				98.20	100.00	2186.99
CHARGE				98.20	100.00	
PRODUCTS						
SULFUR				87.77	89.38	
SULFUR PLANT LOSS				10.43	10.62	
PRODUCTS				98.20	100.00	

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE  
 HYDROGEN PLANT  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LVZ	TONS/D	WTZ	MSCFD
DEBUT OVERHEAD-100R				27.09	1.96	531.26
TRT LP FLASH: JP-8	.5349	289.2	23.27	585.36	42.40	29520.27
TRT DEB OV'D=JP-8				476.74	34.54	7027.35
TRT SPLIT GAS=JP-8				41.90	3.04	867.76
TRT DEP OV'D-JP8				31.88	2.31	613.61
TRT NAP HTRT GAS				.93	.07	102.21
TRT F.O. STAB OV'D				20.94	1.52	1199.58
PLAT NET SEP GAS-100				73.17	5.30	8928.54
PLAT DEBUT GAS-100R	.6643	954.0	76.73	11.44	.83	285.78
LT NAPHTHA JP-8				110.96	8.04	
CHARGE		1243.1	100.00	1380.43	100.00	

## PRODUCTS

HYDROGEN (97%)  
 CO2--HYD. PLT.

752.27	54.50	234287.62
628.16	45.50	
1380.43	100.00	

## PRODUCTS

## Appendix B.7 (Cont.)

DETAILED MATERIAL BALANCE  
 NAPHTHA HYDROTREATER  
 COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LVZ	TONS/D	WTZ	MSCFD
SPLITTER BOTTOMS	.7620	5837.5	97.09	778.81	96.14	
HYDROGEN (97%)				.55	.07	169.79
COLD TREATED WATER	1.0000	175.1	2.91	30.68	3.79	
CHARGE		6012.7	100.00	810.04	100.00	
PRODUCTS						
NAP HYDROTREAT GAS				.93	.12	102.21
SOUR WATER-NAP HT	1.0000	175.1	2.91	30.68	3.79	
TRT HC HVY NAPHTHA	.7616	5837.6	97.09	778.42	96.10	
PRODUCTS		6012.9	100.00	810.04	100.00	

USAF SHALE OIL TO FUELS  
PHASE IV  
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE  
LDP PLATFORMING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
TRT HC HVY NAPHTHA	.7616	5837.6	100.00	778.42	100.00	
CHARGE		5837.6	100.00	778.42	100.00	

PRODUCTS

PLAT NET SEP GAS-100  
PLAT DEBUT GAS-100R  
DEBUT OVERHEAD-100R  
100 RON PLATFORMATE

	73.17	9.40	8928.54
	11.44	1.47	285.78
	27.09	3.48	511.26
	666.71	85.65	
PRODUCTS	778.42	100.00	

PRODUCTS

DETAILED MATERIAL BALANCE  
SOUR WATER TREATING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
SOUR WATER - L.P.HT	1.0000	3558.4	19.85	623.02	19.85	
SOUR WATER - H.P.HT	1.0000	10535.1	58.76	1844.54	58.76	
SOUR WATER (HC)	1.0000	3659.0	20.41	640.63	20.41	
SOUR WATER-NAP HT	1.0000	175.3	.98	30.68	.98	
CHARGE		17927.7	100.00	3138.88	100.00	

PRODUCTS

TREATED SOUR WATER  
AMMONIA  
LOSS

	1.0000	16231.9	90.54	2841.97	90.54	
				291.34	9.28	
				5.57	.18	
PRODUCTS		16231.9	90.54	3138.88	100.00	

DETAILED MATERIAL BALANCE  
AMINE REGENERATION  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
				98.20	100.00	2186.99
				98.20	100.00	
				98.20	100.00	2186.99
				98.20	100.00	

PRODUCTS

AMMONIA

AD-A130 374

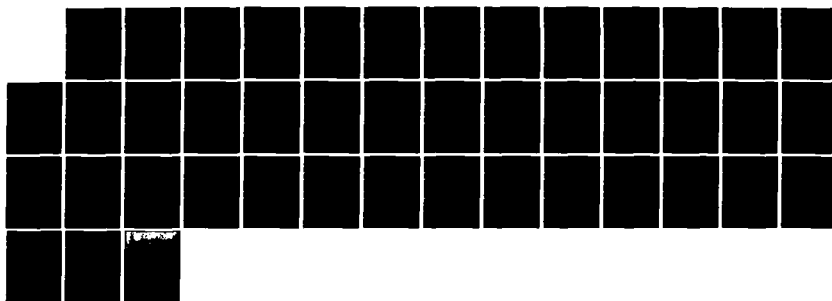
USAF SHALE OIL TO FUELS VOLUME 2 PHASES 3 AND 4(U) UOP  
INC DES PLAINES IL PROCESS DIV J G SIKONIA ET AL.  
JUL 82 AFMNL-TR-81-2116-VOL-2 F33615-78-C-2079

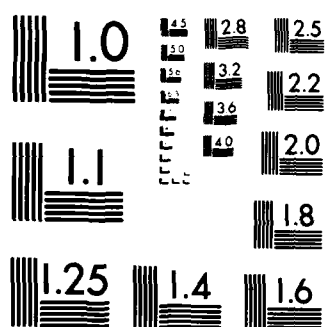
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USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE  
 ANTONIA PLANT  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BSL/D	LVZ	TONS/D	MTZ	MSCFD
ANTONIA				291.34	100.00	
CHARGE				291.34	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	83.8		14.66	5.03	
ANHYDROUS ANTONIA				276.68	94.97	
PRODUCTS		83.8		291.34	100.00	

DETAILED MATERIAL BALANCE  
 FUEL OIL STABILIZER  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BSL/D	LVZ	TONS/D	MTZ	MSCFD
SEPARATOR LIQUID(HP)	.8377	8458.7	100.00	1240.63	100.00	
CHARGE		8458.7	100.00	1240.63	100.00	
PRODUCTS						
F.O. STAB OVER'D	.8640	8052.2	95.19	22.54	1.82	1235.32
F.O. STAB BOTTOMS				1218.09	98.18	
PRODUCTS		8052.2	95.19	1240.63	100.00	

DETAILED MATERIAL BALANCE  
 COMBINED FACILITIES  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BSL/D	LVZ	TONS/D	MTZ	MSCFD
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

USAF SHALE OIL TO FUELS  
PHASE IV

CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED MATERIAL BALANCE  
UDP PLATFORMING  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
TRT HC WVT NAPHTHA	.7616	5837.6	100.00	778.42	100.00	
CHARGE		5837.6	100.00	778.42	100.00	
PRODUCTS						
PLAT NET SEP GAS-100				73.17	9.40	8928.54
PLAT DEBUT GAS-100R				11.44	1.47	285.78
DEBUT OVERHEAD-100R	.5349	289.2	4.95	27.09	3.48	531.26
100 RON PLATFORMATE	.8233	4625.2	79.23	666.71	85.65	
PRODUCTS		4914.5	84.19	778.42	100.00	

## Appendix B.7 (Cont.)

DETAILED MATERIAL BALANCE  
SOUR WATER TREATING  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
SOUR WATER - L.P.HT	1.0000	3558.4	19.85	623.02	19.85	
SOUR WATER - H.P.HT	1.0000	10535.1	58.76	1844.54	58.76	
SOUR WATER (HC)	1.0000	3659.0	20.41	640.63	20.41	
SOUR WATER-NAP HT	1.0000	175.3	.98	30.68	.98	
CHARGE		17927.7	100.00	3138.88	100.00	

## PRODUCTS

TREATED SOUR WATER  
AMMONIA  
LOSS

## PRODUCTS

1.0000	16231.9	90.54	2841.97	90.54	
			291.34	9.28	
			5.57	.18	

DETAILED MATERIAL BALANCE  
AMINE REGENERATION  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
HYDROGEN SULFIDE				98.20	100.00	2186.99
CHARGE				98.20	100.00	
PRODUCTS						
HYDROGEN SULFIDE				98.20	100.00	2186.99
PRODUCTS				98.20	100.00	

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USAF SHALE OIL TO FUELS  
PHASE IV

CASE 3 - MAXIMUM JP-8 JET FUEL

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DETAILED MATERIAL BALANCE  
DUTY UNIT  
COMPOSITE YIELDS

	SP. GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
CHARGE						
MIXED BUTANES	.5743	840.6	100.00	84.52	100.00	
CHARGE						
		840.6	100.00	84.52	100.00	
PRODUCTS						
MIXED BUTANES	.5743	840.6	100.00	84.52	100.00	
PRODUCTS						
		840.6	100.00	84.52	100.00	

Appendix B.7 (Cont.)

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY  
 ELECTRIC POWER UNIT IS KWH  
 COSTS ARE ALLOCATED TO PROCESS UNITS

PRICE IS .04500/UNIT

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1080	.673	9720.85	437.44
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	1.9070	11.884	171627.72	7723.25
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	1.2677	8.160	117422.70	5284.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	7.0969	48.387	638481.09	28731.74
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40	.3911	3.424	8993.59	404.71
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16433.9	1804.78	.3399	1.289	2327.09	104.72
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47	.1200	1.256	147.51	6.64
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		21.974	2157.87	97.10
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27		233.790	175873.57	7914.31
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81	.7065	5.296	4124.25	185.59
LOOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	2.4382	18.285	14233.16	640.50
SOLAR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88	.3787	2.163	6788.77	305.49
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20		40.773	4003.95	180.18
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68		3.393	938.71	42.24
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63	.1638	1.116	1395.16	62.33
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUPPY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				

TOTALS

1158228.20

52120.27

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
 600# STEAM UNIT IS HLBS  
 COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0193	.120	1733.03	
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0158	.102	1462.05	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.0075	.051	676.92	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20	.220		21.57	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27	-5.317		-3999.61	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81				
LDP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	- .0603		-351.77	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20				
ATTORILLA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							-457.81	
AMOUNT PRODUCED FROM REFINERY FUELS							4151.36	2830.48
AMOUNT CONVERTED TO 150# STEAM							4141.01	
AMOUNT CONVERTED TO 50# STEAM							448.17	

Appendix B.7 (Cont.)

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY  
 COOLING WATER UNIT IS MEAL PRICE IS .03000/UNIT  
 COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0016	.010	145.86	4.38
N.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.14	.0398	.271	3578.58	107.16
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40	.0299	.261	686.80	20.60
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78	.0116	.107	192.39	5.77
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47	.0857	.897	105.33	3.16
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		1176.39				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE		752.27		.806	606.02	18.18
LOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81	.0118	.089	69.16	2.07
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.82	.0848	.616	494.92	14.85
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.83	.1336	.763	2395.10	71.85
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		32.389	3180.63	95.42
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63		10.961	3032.67	90.98
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0200	.137	169.59	5.09
CLIPPY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							16657.06	489.71

Appendix B.7 (Cont.)

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
 REFINERY FUELS UNIT IS FHTU  
 COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0218	.136	1961.21	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.0482	.310	4466.72	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40	.1729	1.179	15533.35	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78	.0640	.560	1472.10	
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81	.0170	57.884	43544.29	
WOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	.1238	.127	99.06	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88		2.928	1890.11	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20				
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63	.0486	.331	433.27	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUPPY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							69188.32	
AMOUNT PRODUCED FROM F.O. STAB BOTTOMS							42754.91	
AMOUNT PRODUCED FROM LT NAPHTHA JP-8							30417.19	
AMOUNT CONVERTED TO 600# STEAM							3773.98	

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
 150# STEAM UNIT IS MUBS  
 COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		1176.39		-7.593	-745.65	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE		752.27				
LOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.42	.0007	.005	4.05	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88	.2633	1.504	4719.58	
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		98.20		1.660	163.03	
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	276.68				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	1240.63				
DUTTY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	14441.92				
TOTALS				84.52			4141.01	
AMOUNT PRODUCED FROM 600# STEAM							4141.01	

Appendix B.7 (Cont.)

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USAF SHALE OIL TO FUELS

PHASE IV

CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
50# STEAM UNIT IS MLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BSL/D	TONS/D	UNIT/BSL	UNIT/TON	UNITS/D	9/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13155.14	-0.031	-0.021	-278.62	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78	.0460	.424	765.41	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47	.0276	.289	31.93	
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		1176.39		-9.864	-968.63	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	752.27				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.61				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	778.42				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		3138.88		9.327	915.88	
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	276.68				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	1240.63				
DUTTY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	14441.92				
TOTALS				84.52			468.17	
AMOUNT PRODUCED FROM 600# STEAM							468.17	

USAF SHALE OIL TO FUELS  
PHASE IV  
CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
BOILER WATER UNIT IS MILBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.0112	.076	1006.80	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20	18.946	18.946	1860.52	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27	17.088	17.088	12854.46	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	778.81				
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5837.5	778.42	.0987	.740	576.18	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20				
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							16197.97	
AMOUNT PURCHASED							5560.86	2780.43
AMOUNT PRODUCED FROM CONDENSATE							10737.11	

Appendix B.7 (Cont.)

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF A POOLED UTILITY  
 CONDENSATE UNIT IS HLBS  
 COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	¢/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	11195.34				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE						
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE						
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE						
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5837.5	752.27				
LOP PLATFORING	COMBINED MODES	COMPOSITE USAGE	5837.6	778.81				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	778.42				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE						
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE						
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	276.68				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				

## TOTALS

-10737.11

## AMOUNT CONVERTED TO BOILER WATER

10737.11

Appendix B.7 (Cont.)

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

DETAILED USAGE OF AN UNPOOLED UTILITY  
 CAT. & CHEMICALS UNIT IS \$  
 COSTS ARE ALLOCATED TO PROCESS UNITS

PRICE IS 1.00000/UNIT.

PROCESS UNIT	MODE	CONTROL STREAM	BSL/D	TONS/D	UNIT/BSL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1145	.714	10308.64	10308.64
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0417	.268	3958.02	3958.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	89966.8	13195.34	.0699	.477	6290.22	6290.22
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	22993.1	2626.40				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	16633.9	1804.78				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	1229.3	117.47				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		1176.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.20				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		752.27		8.019	3775.87	3775.87
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	5937.5	778.81	.0028	.021	16.59	16.59
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	5937.6	778.42	.0569	.426	331.99	331.99
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17927.7	3138.88				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.20		.283	27.75	27.75
ATTONTIA PLANT	COMBINED MODES	COMPOSITE USAGE		276.68				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	8458.7	1240.63				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUTTY UNIT	COMBINED MODES	COMPOSITE USAGE	840.6	84.52				
TOTALS							24609.08	24609.08

Appendix B.7 (Cont.)

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 3 - MAXIMUM JP-8 JET FUEL

## PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	ELECTRIC POWER KWH	600# STE AM MLBS	COOLING WATER MGAL	REFINERY FUELS MMBTU	150# STE AM MLBS	50# STE AM MLBS	BOILER W ATER MLBS	CONDENSA TE MLBS
FEED PREPARATION	9720.9							
L.P. HYDROTREATING	171627.7	1733.0	145.9	1961.2				-1733.0
H.P. HYDROTREATING	117422.7	1462.0		4456.7				-1462.0
HYDROCRACKING	638483.1	676.9	3578.6	15553.4		-278.4	1006.8	-676.9
NAPHTHA SPLITTER	8993.6		686.8	1472.1				
DEBUTANIZER	2327.1		192.4			765.4		-765.4
DEPROPANIZER	147.5		105.3			33.9		-33.9
SULFUR PLANT	2157.9	21.6			-745.7	-968.6	1860.5	-67.1
HYDROGEN PLANT	175873.6	-3999.6	606.0	43544.3			12854.5	
NAPHTHA HYDROTREATER	4124.2		69.2	99.1				
UOP PLATFORMING	14233.4	-351.8	494.9	1890.3			576.2	-200.1
SOUR WATER TREATING	6788.8		2195.1		4.0			
AMINE REGENERATION	4004.0		3180.6		4719.6			-4719.6
ATFONIA PLANT	938.7		3032.7		163.0	915.9		-1078.9
FUEL OIL STABILIZER	1385.2		169.6	411.3				
TOTAL CONSUMPTION	1158228.2	-657.8	14657.1	69398.3	4141.0	468.2	16298.0	-10737.1

Appendix B.7 (Cont.)

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 3 - MAXIMUM JP-8 JET FUEL

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PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	CAT. & C HEMICALS
FEED PREPARATION	
L.P. HYDROTREATING	10308.6
H.P. HYDROTREATING	3858.0
HYDROCRACKING	6290.2
NAPHTHA SPLITTER	
DEBUTANIZER	
SULFUR PLANT	
HYDROGEN PLANT	3775.9
NAPHTHA HYDROTREATER	16.6
LOP PLATFORMING	332.0
SOLR WATER TREATING	
AMINE REGENERATION	27.8
ATTOMIA PLANT	
FUEL OIL STABILIZER	
TOTAL CONSUMPTION	24609.1

## JP-8 PLUS DIESEL CASE -- STANDARD OPTIMIZATION REPORT

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0  
 USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 4 - JP-8 JET FUEL + DF-2/DFH DIESEL

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## GROSS MARGIN SUMMARY

SALES MARKET	PRODUCT	MAXIMUM	QUANTITY LIMITS MINIMUM	FIXED	QUANTITY SOLD	PRICE	TOTAL \$/DAY
A	UNLEADED GASOLINE				3169.30 BBL	57.5500	1826573.30
A	AV TURBINE FUEL JP-8				49697.18 BBL	57.8500	2924479.04
A	DF-2/DF-H DIESEL				26894.99 BBL	57.5500	1572782.16
A	SULFUR				87.75 TON	98.4500	8376.17
A	ANTHYRUS ATTENDIA				278.08 TON	155.0000	42781.61
TOTAL SALES REVENUE							4745100.28
RAW MATERIAL PURCHASED	MATERIAL	QUANTITY LIMITS	QUANTITY PURCHASED	PRICE	TOTAL		
	OCCIDENTAL SHALE OIL		90000.0	40.0000	3600000.00		
	COLD TREATED WATER		14504.43 BBL	.0248	358.36		
	80# STRIPPING STEAM		159.92 TON	.0000	.00		
TOTAL RAW MATERIAL COST					3600358.36		
GROSS MARGIN					1144741.92		

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## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

USAF SHALE OIL TO FUELS  
PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## OPERATING COST SUMMARY

PROCESS UNIT	MODE	CONTROL	STREAM	BBU/D	QUANTITY TON/D	\$/BBL	OPERATING COST \$/TON	\$/D
FEED PREPARATION	COMBINED MODES		COMPOSITE COST	90000.0	14441.92	.029556	.18419	2660.05
L.P. HYDROTREATING	COMBINED MODES		COMPOSITE COST	90000.0	14441.92	.294147	1.83308	26473.23
H.P. HYDROTREATING	COMBINED MODES		COMPOSITE COST	92629.0	14390.21	.218964	1.53820	22134.96
HYDROCRACKING	COMBINED MODES		COMPOSITE COST	84888.1	12450.46	.627371	6.27746	53256.34
NAPHTHA SPLITTER	COMBINED MODES		COMPOSITE COST	11848.5	1338.05	.081954	.72571	921.03
DEBUTANIZER	COMBINED MODES		COMPOSITE COST	8676.8	933.38	.110762	1.02965	961.06
DEPROPANIZER	COMBINED MODES		COMPOSITE COST	635.9	60.19	.028065	8.74930	526.59
FUEL GAS TREATER	COMBINED MODES		COMPOSITE COST	766.39	766.39		.92290	707.30
SULFUR PLANT	COMBINED MODES		COMPOSITE COST	98.18	98.18		19.67483	1931.70
HYDROGEN PLANT	COMBINED MODES		COMPOSITE COST	715.82	715.82		38.80267	2775.71
NAPHTHA HYDROTREATER	COMBINED MODES		COMPOSITE COST	2588.2	345.31	.530560	3.97677	1373.20
UOP FLATFORING	COMBINED MODES		COMPOSITE COST	2588.3	345.13	1.184450	8.88260	3065.68
SOUR WATER TREATING	COMBINED MODES		COMPOSITE COST	17623.6	3085.64	.207060	1.18263	3649.15
AMINE REGENERATION	COMBINED MODES		COMPOSITE COST	98.18	98.18		17.81405	1749.01
ANTHONIA PLANT	COMBINED MODES		COMPOSITE COST	275.88	275.88		2.68881	741.79
FUEL OIL STABILIZER	COMBINED MODES		COMPOSITE COST	13537.4	1985.51	.077477	.52824	1048.83
COMBINED FACILITIES	COMBINED MODES		COMPOSITE COST	90000.0	14441.92	.098029	.61090	8822.57
DUPPY UNIT	COMBINED MODES		COMPOSITE COST	405.4	40.78			

## TOTAL PROCESS UNIT OPERATING COST

157849.21

UTILITY PURCHASES	UTILITY	UNIT	UNITS/D	\$/UNIT	\$/D
BOILER WATER		MLBS	9824.12	.50000	4912.06
TOTAL UTILITY PURCHASES					4912.06
UTILITY SALES	UTILITY	UNIT	UNITS/D	\$/UNIT	\$/D
50# STEAM		MLBS	625.78	.00010	.06
TOTAL UTILITY SALES					.06

UTILITY PRODUCTION COSTS	UTILITY	UNIT	UNITS/D	SOURCE	\$/D
600# STEAM		MLBS	754.67	REFINERY FUELS	514.55
TOTAL UTILITY PRODUCTION COSTS					514.55

## TOTAL OPERATING COST

163274.76

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## CAPITAL COST SUMMARY

PROCESS UNIT	MODE	CONTROL STREAM	QBL/D	QUANTITY TON/D	\$/BBL	CAPITAL COST \$/TON	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.096215	.59960	8659.38
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.633231	3.94621	56990.78
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE COST	92629.0	14390.21	.997898	6.42342	92434.31
HYDROCRACKING	COMBINED MODES	COMPOSITE COST	84988.1	12450.46	1.908267	13.01071	161989.29
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE COST	11848.5	1338.05	.130502	1.15560	1546.25
DEBUTANIZER	COMBINED MODES	COMPOSITE COST	8676.8	933.38	.314447	2.92312	2728.40
DEPROPANIZER	COMBINED MODES	COMPOSITE COST	635.9	60.19	1.035242	10.93832	659.33
FUEL GAS TREAT	COMBINED MODES	COMPOSITE COST		766.39		1.56139	1196.64
SULFUR PLANT	COMBINED MODES	COMPOSITE COST		98.18		57.38291	5633.94
HYDROGEN PLANT	COMBINED MODES	COMPOSITE COST		715.82		163.08393	116738.64
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE COST	2588.2	345.31	.775609	5.81350	2007.44
LOP PLATFORING	COMBINED MODES	COMPOSITE COST	2588.3	345.13	2.291712	17.18633	5931.57
SOUR WATER TREATING	COMBINED MODES	COMPOSITE COST	17623.6	3085.64	.529845	3.02621	9337.79
AMINE REGENERATION	COMBINED MODES	COMPOSITE COST		98.18		26.64689	2616.23
ATFONIA PLANT	COMBINED MODES	COMPOSITE COST		275.88		1.50753	415.90
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE COST	13537.4	1985.51	.214207	1.46048	2899.80
COMBINED FACILITIES	COMBINED MODES	COMPOSITE COST	90000.0	14441.92	.135235	.73813	10371.11
DUMMY UNIT	COMBINED MODES	COMPOSITE COST	405.4	40.78			
TOTAL							482155.78

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, PS1.0

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## USAF SHALE OIL TO FUELS

## PHASE IV

CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## MATERIAL BALANCE SUMMARY

CHARGE	SP. GR.	BBU/O	LV%	TONS/O	WT%	MSCFD
OCCIDENTAL SHALE OIL	.91650	90000.0	86.121	14441.92	84.252	
COLD TREATED WATER	1.00000	14504.4	13.879	2539.51	14.815	
50# STRIPPING STEAM				159.99	.933	
TOTAL CHARGE		104504.4	100.000	17141.42	100.000	
PRODUCTS	SP. GR.	BBU/O	LV%	TONS/O	WT%	MSCFD
UNLEADED GASOLINE	.76091	3169.3	3.033	422.23	2.463	
AV TURBINE FUEL JP-8	.80500	49697.2	47.555	7004.50	40.863	
DF-2/DF-M DIESEL	.81580	26895.0	25.736	3935.71	22.960	
SULFUR				87.75	.512	
ANHYDRUS AMMONIA				275.88	1.609	
TOTAL PRODUCTS SOLD		79761.5	76.324	11726.08	68.408	
STREAMS CONVERTED TO UTILITIES	SP. GR.	BBU/O	LV%	TONS/O	WT%	MSCFD
F.O. STAB BOTTOMS	.86400	12886.8	12.331	1949.44	11.373	
TOTAL STREAMS CONVERTED		12886.8	12.331	1949.44	11.373	
STREAMS NOT UTILIZED	SP. GR.	BBU/O	LV%	TONS/O	WT%	MSCFD
LOSS						
SULFUR PLANT LOSS				27.04	.158	
CO2--HYD. PLT.				10.43	.061	
TREATED SOUR WATER	1.00000	16016.2	15.326	624.23	3.642	
TOTAL NOT UTILIZED		16016.2	15.326	2804.20	16.359	
TOTAL PRODUCTS MADE		108664.5	103.981	17141.42	100.000	

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + QF-2/DPM DIESEL

## PLANT CAPACITY SUMMARY INVESTMENT CAPACITY UNITS/DAY

UNIT	CAPACITY CATEGORY	MAXIMUM	MINIMUM	FIXED	LP INPUT	ACTUAL	INVESTMENT
FEED PREPARATION	CAPACITY BBL/S/CD				90000.0	90004.9	9030000
L.P. HYDROTREATING	CAPACITY BBL/S/CD				90000.0	90004.9	59430000
H.P. HYDROTREATING	CAPACITY BBL/S/CD				92630.0	92635.6	96390000
HYDROCRACKING	CAPACITY BBL/S/CD				84887.5	84887.5	168931683
NAPHTHA SPLITTER	CAPACITY BBL/S/CD				11849.6	11849.6	1612516
DEBUTANIZER	CAPACITY BBL/S/CD				8677.4	8677.4	2845328
DEPROPANIZER	CAPACITY BBL/S/CD				636.0	636.0	686548
FUEL GAS TREATER	CAPACITY TONS/CD				766.4	766.4	1247922
SULFUR PLANT	CAPACITY TONS/CD				98.2	98.2	5875389
HYDROGEN PLANT	CAPACITY TONS/CD				715.8	715.8	121741719
NAPHTHA HYDROTREATER	CAPACITY BBL/S/CD				2588.2	2588.2	2093469
LOP PLATFORING	CAPACITY BBL/S/CD				2479.6	2479.6	6185784
SOUR WATER TREATING	CAPACITY BBL/S/CD				17714.1	17714.1	9737981
AMINE REGENERATION	CAPACITY TONS/CD				98.2	98.2	2728353
ATTOMIA PLANT	CAPACITY TONS/CD				275.9	275.9	433723
FUEL OIL STABILIZER	CAPACITY BBL/S/CD				13537.2	13537.2	3024072
COMBINED FACILITIES	CAPACITY BBL/S/CD				90000.0	90004.9	10815000

TOTAL OPTIMIZED INVESTMENT

502809487

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USAF SHALE OIL TO FUELS  
PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## PRODUCT BLENDING

UNLEADED GASOLINE	BSL/D	TONS/D	SPGR@60F	WT% SULF	RES OCTN	MOT OCTN	(R+M)12	RVP INDX	VL% AROM	D+L 131F
SPLITTER BOTTOMS	251.6	33.56	.7620	.0003	59.0000	57.0000	58.0000	3.1000	7.0000	.0000
LT NAPHTHA JP-8 DM	409.0	47.44	.6625	.0003	75.0000	73.0000	74.0000	175.0000	2.0000	51.0000
99 RON PLATFORHATE	2103.1	300.44	.8159	.0003	98.0000	87.0000	92.5000	53.3000	68.6000	.5000
MIXED BUTANES	405.6	40.78	.5743	.0003	98.5000	94.3000	96.4000	1280.0000	.0000	100.0000
BLEND	3169.3	422.23	.7609	.0003	92.0000	83.7461	87.8730	222.0000	46.3350	19.7106
SPECIFICATIONS		MAX		.1000				222.0000	55.0000	
		MIN			92.0000	82.0000	87.0000			10.0000

## PRODUCT BLENDING

UNLEADED GASOLINE	BSL/D	TONS/D	D+L 171F	D+L 235F	D+L 365F	D+L 437F
SPLITTER BOTTOMS	251.6	33.56	1.0000	41.0000	100.0000	100.0000
LT NAPHTHA JP-8 DM	409.0	47.44	96.0000	100.0000	100.0000	100.0000
99 RON PLATFORHATE	2103.1	300.44	6.0000	40.0000	100.0000	100.0000
MIXED BUTANES	405.6	40.78	100.0000	100.0000	100.0000	100.0000
BLEND	3169.3	422.23	29.2471	55.5008	100.0000	100.0000
SPECIFICATIONS		MAX	50.0000			100.0000
		MIN		50.0000	90.0000	

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## PRODUCT BLENDING

AV TURBINE FUEL JP-8	BBL/D	TONS/D	SPGR260F	MT% SULF	VL% AROM	SHOKE PT	FREEZ PT	VL% NAPH	FLASH PT	D+L 401F
HC KEROSENE: 300-550F	49697.2	7004.50	.8050	.0003	10.0000	24.0000	-58.0000	1.5000	100.0000	40.0000
BLEND	49697.2	7004.50	.8050	.0003	10.0000	24.0000	-58.0000	1.5000	100.0000	40.0000
SPECIFICATIONS		MAX MIN	.8398 .7753	.4000	25.0000	20.0000	-59.0000	3.0000	100.0000	10.0000

## PRODUCT BLENDING

AV TURBINE FUEL JP-8	BBL/D	TONS/D	D+L 572F
HC KEROSENE: 300-550F	49697.2	7004.50	100.0000
BLEND	49697.2	7004.50	100.0000
SPECIFICATIONS		MAX MIN	100.0000

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## PRODUCT BLENDING

DF-2/DF-M DIESEL	BBL/D	TONS/D	SPGR360F	WT% SULF	FLASH PT	CETANE I	D+L 700F	VIS 100F	FOUR PT.	CLOUD PT
HC DIESEL: 550-700F	26895.0	3935.71	.8358	.0003	288.0000	56.0000	100.0000	18.4000	.0000	5.0000
BLEN0	26895.0	3935.71	.8358	.0003	288.0000	56.0000	100.0000	18.4000	.0000	5.0000
SPECIFICATIONS		MAX	.8607	.7000			100.0000	18.4100	.0000	5.0000
		MIN	.8203		133.0000	45.0000		10.3100		

## PRODUCT BLENDING

DF-2/DF-M DIESEL	BBL/D	TONS/D	D+L 675F	D+L 725F
HC DIESEL: 550-700F	26895.0	3935.71	90.0000	100.0000
BLEN0	26895.0	3935.71	90.0000	100.0000
SPECIFICATIONS		MAX	100.0000	
		MIN	90.0000	

## PRODUCT BLENDING

SULFUR	BBL/D	TONS/D	SPGR360F
SULFUR		87.75	
BLEN0		87.75	

NO SPECIFICATIONS

## PRODUCT BLENDING

ANHYDRUS ATOMIA	BBL/D	TONS/D	SPGR360F
ANHYDRUS ATOMIA		275.88	
BLEN0		275.88	

NO SPECIFICATIONS

## RECYCLE STREAM BLENDING

MIXED BUTANES	BBL/D	TONS/D	SPGR360F
MIXED C4'S: JP-8 DM	343.6	34.55	.5744
MIXED C4'S: 98R PLT	61.8	6.23	.5756
BLEN0	405.4	40.78	.5746

NO SPECIFICATIONS

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## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, PS1.0

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## BLEND FOR UTILITY PRODUCTION

REFINERY FUELS	BBL/D	TONS/D	SPGR360F
F.O. STAB BOTTOMS	12886.8	1949.44	.8640
BLEND	12886.8	1949.44	.8640

NO SPECIFICATIONS

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 4 - JP-8 JET FUEL + DF-2/DFH DIESEL

DETAILED MATERIAL BALANCE  
 FEED PREPARATION  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
DEASHED SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

DETAILED MATERIAL BALANCE  
 L.P. HYDROTREATING  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
DEASHED SHALE OIL	.9165	90000.0	97.09	14441.92	95.66	
HYDROGEN (97%)				182.55	1.21	56852.12
COLD TREATED WATER	1.0000	2700.6	2.91	472.83	3.13	
CHARGE		92700.6	100.00	15097.29	100.00	
PRODUCTS						
SOUR WATER - L.P.H.T	1.0000	3558.4	3.84	623.02	4.13	
HYDROGEN SULFIDE				79.57	.53	1772.18
SEPARATOR LIQUID(LP)	.8873	92629.0	99.92	14390.21	95.32	
LOSS				4.48	.03	
PRODUCTS		96187.4	101.76	15097.29	100.00	

DETAILED MATERIAL BALANCE  
 H.P. HYDROTREATING  
 COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
SEPARATOR LIQUID(LP)	.8873	92629.0	90.91	14390.21	88.34	
HYDROGEN (97%)				277.30	1.70	86362.21
COLD TREATED WATER	1.0000	9263.6	9.09	1621.92	9.96	
CHARGE		101892.6	100.00	16289.43	100.00	
PRODUCTS						
SOUR WATER - H.P.H.T	1.0000	10535.1	10.34	1844.54	11.32	
SEPARATOR LIQUID(H.P.)	.8377	98425.5	96.60	14435.97	88.62	
LOSS				8.92	.05	
PRODUCTS		108960.6	106.94	16289.43	100.00	

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## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DPH DIESEL

DETAILED MATERIAL BALANCE  
HYDROCRACKING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LV%	TONS/D	WT%	MSCFD
SEPARATOR LIQUID (HP)	.8377	84889.1	97.18	12450.46	93.63	
HYDROGEN (97%)				255.73	1.92	79645.39
COLD TREATED WATER	1.0000	2462.6	2.82	431.16	3.24	
50# STRIPPING STEAM				159.99	1.20	
CHARGE		87350.7	100.00	13297.34	100.00	
PRODUCTS						
LP FLASH GAS: JP8-DH				406.51	3.06	25083.83
PROD FRACT OV: JP8-DH	.6450	11848.5	13.56	1338.05	10.06	
SOUR WATER (HC)	1.0000	3452.4	3.95	604.47	4.55	
HC KEROSENE: 300-550F	.8050	49697.2	56.89	7004.50	52.68	
HC DIESEL: 550-700F	.8358	26895.0	30.79	3935.71	29.60	
LOSS				8.09	.06	
PRODUCTS		91893.1	105.20	13297.34	100.00	

DETAILED MATERIAL BALANCE  
NAPHTHA SPLITTER  
COMPOSITE YIELDS

CHARGE	SP. GR.	BSL/D	LV%	TONS/D	WT%	MSCFD
PROD FRACT OV: JP8-DH	.6450	11848.5	100.00	1338.05	100.00	
CHARGE		11848.5	100.00	1338.05	100.00	
PRODUCTS						
SPLITTER GAS: JP8-DH				25.80	1.93	601.35
SPLIT OV LIQ: JP8-DH	.6144	8676.8	73.23	933.38	69.76	
SPLITTER BOTTOMS	.7620	2839.8	23.97	378.87	28.31	
PRODUCTS		11516.6	97.20	1338.05	100.00	

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USAF SHALE OIL TO FUELS  
PHASE IV

CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
DEBUTANIZER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LVZ	TONS/D	WTZ	HSCFD
SPLIT OV LIQ=JP8-OH	.6144	8676.8	100.00	933.38	100.00	
CHARGE		8676.8	100.00	933.38	100.00	
PRODUCTS						
DEBUT OVER'D=JP8-OH	.5418	3457.2	39.84	327.95	35.14	4972.24
LT NAPHTHA JP-8 OH	.6625	5219.5	60.15	605.43	64.86	
PRODUCTS		8676.7	100.00	933.38	100.00	

DETAILED MATERIAL BALANCE  
DEPROPANIZER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBL/D	LVZ	TONS/D	WTZ	HSCFD
DEBUT OVER'D=JP8-OH	.5418	524.6	82.49	49.76	82.68	754.48
DEBUT OVERHEAD-98R	.5347	111.3	17.51	10.42	17.32	204.42
CHARGE		635.9	100.00	60.19	100.00	
PRODUCTS						
DEPROP OV'D JP-8 OH	.5744	343.6	54.03	15.21	25.27	303.93
MIXED C4'S JP-8 OH				34.55	57.41	
DEPROP OV'D-98R PLT	.5756	63.8	9.72	4.20	6.97	79.68
MIXED C4'S-98R PLT				6.23	10.35	
PRODUCTS		405.4	63.75	60.19	100.00	

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
FUEL GAS TREATER  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
LP FLASH GAS=JP8-OH				406.51	53.04	25083.83
DEBUT OVER'D=JP8-OH				278.19	36.30	4217.77
SPLITTER GAS=JP8-OH	.5418	2932.6	100.00	25.80	3.37	601.35
DEPRO OV'D JP-8 OH				15.21	1.98	303.93
NAP HYDROTREAT GAS				.41	.05	45.32
F.O. STAB OVER'D				36.08	4.71	1977.01
DEPRO OV'D-98R PLT				4.20	.55	79.68
CHARGE		2932.6	100.00	766.39	100.00	

## PRODUCTS

HYDROGEN SULFIDE				18.61	2.43	414.38
TRT LP FLASH=JP8-OH				396.47	51.73	24848.09
TRT DEB OV'D=JP8-OH				273.82	35.73	4120.27
TRT SPLIT GAS=JP8-OH				24.94	3.25	582.28
TRT DEP OV'D-JP8 OH				14.43	1.89	286.53
TRT NAP HTRT GAS				.41	.05	45.32
TRT F.O. STAB OV'D				33.52	4.37	1919.81
TRT DEPRO OV-98R PLT				4.20	.55	79.68
PRODUCTS				766.39	100.00	

DETAILED MATERIAL BALANCE  
SULFUR PLANT  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WTZ	MSCFD
HYDROGEN SULFIDE				98.18	100.00	2186.55
CHARGE				98.18	100.00	
PRODUCTS						
SULFUR				87.75	89.38	
SULFUR PLANT LOSS				10.43	10.62	
PRODUCTS				98.18	100.00	

## USAF SHALE OIL TO FUELS

## PHASE IV

CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
HYDROGEN PLANT  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	MSCFD
TRT LP FLASH-JP8-DH				396.47	29.59	24848.09
TRT DEB OV'D-JP8-DH				273.82	20.43	4120.27
TRT SPLIT GAS-JP8-DH				24.94	1.86	582.28
TRT DEP OV'D-JP8 DH				14.43	1.08	286.51
TRT DEPRO OV-98R PLT				4.20	.31	79.68
TRT NAP HTRT GAS				.41	.03	45.32
TRT F.O. STAB OV'D				33.52	2.50	1919.81
PLAT NET SEP GAS-98R				29.09	2.17	3742.77
PLAT DEBUT GAS-98R				5.18	.39	129.46
LT NAPHTHA JP-8 DH	.6625	4810.5	100.00	557.99	41.64	
CHARGE		4810.5	100.00	1340.05	100.00	

## PRODUCTS

HYDROGEN (97%)  
CO2-HYD. PLT.

715.82	53.42	222935.00
624.23	46.58	
1340.05	100.00	

## PRODUCTS

DETAILED MATERIAL BALANCE  
NAPHTHA HYDROTREATER  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LVZ	TONS/D	WT%	MSCFD
SPLITTER BOTTOMS	.7620	2588.2	97.09	345.31	96.14	
HYDROGEN (97%)				.24	.07	75.28
COLD TREATED WATER	1.0000	77.7	2.91	13.61	3.79	
CHARGE		2665.9	100.00	359.15	100.00	
PRODUCTS						
NAP HYDROTREAT GAS				.41	.12	45.32
SOUR WATER-NAP HT	1.0000	77.7	2.91	13.61	3.79	
TRT HC HVT NAPHTHA	.7616	2588.3	97.09	345.13	96.10	
PRODUCTS		2666.0	100.00	359.15	100.00	

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
LUP PLATFORMING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
TRT HC WY NAPHTHA	.7616	2588.3	100.00	345.13	100.00	
CHARGE		2588.3	100.00	345.13	100.00	
PRODUCTS						
PLAT NET SEP GAS-98R				29.09	8.43	3742.77
PLAT DEBUT GAS-98R				5.18	1.50	129.46
DEBUT OVERHEAD-98R	.5347	111.3	4.30	10.42	3.02	204.42
98 RON PLATFORMATE	.8159	2103.1	81.26	300.44	87.05	
PRODUCTS		2214.5	85.56	345.13	100.00	

DETAILED MATERIAL BALANCE  
SOUR WATER TREATING  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
SOUR WATER - L.P.MT	1.0000	3558.4	20.19	623.02	20.19	
SOUR WATER - M.P.MT	1.0000	10535.1	59.78	1844.54	59.78	
SOUR WATER (MC)	1.0000	3452.4	19.59	604.47	19.59	
SOUR WATER-NAP MT	1.0000	77.7	.44	13.61	.44	
CHARGE		17623.6	100.00	3065.64	100.00	
PRODUCTS						
TREATED SOUR WATER	1.0000	15932.7	90.41	2789.58	90.41	
AMMONIA LOSS				290.50	9.41	
PRODUCTS		15932.7	90.41	5.55	.16	

DETAILED MATERIAL BALANCE  
AMINE REGENERATION  
COMPOSITE YIELDS

CHARGE	SP. GR.	BBL/D	LV%	TONS/D	WT%	MSCFD
HYDROGEN SULFIDE				98.18	100.00	2186.55
CHARGE				98.18	100.00	
PRODUCTS						
HYDROGEN SULFIDE				98.18	100.00	2186.55
PRODUCTS				98.18	100.00	

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFH DIESEL

DETAILED MATERIAL BALANCE  
ANTONIA PLANT  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBU/D	LV%	TONS/D	WT%	MSCFD
ANTONIA						
CHARGE						
				290.50	100.00	
PRODUCTS				290.50	100.00	
TREATED SOUR WATER	1.0000	83.5		14.62	5.03	
ANHYDRUS ANTONIA				275.88	94.97	
PRODUCTS		83.5		290.50	100.00	

DETAILED MATERIAL BALANCE  
FUEL OIL STABILIZER  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBU/D	LV%	TONS/D	WT%	MSCFD
SEPARATOR LIQUID (HP)	.8377	13537.4	100.00	1985.51	100.00	
CHARGE		13537.4	100.00	1985.51	100.00	
PRODUCTS						
				36.08	1.82	1977.01
F.O. STAB OVER'D	.8640	12886.8	95.19	1949.44	98.18	
F.O. STAB BOTTOMS		12886.8	95.19	1985.51	100.00	
PRODUCTS						

DETAILED MATERIAL BALANCE  
COMBINED FACILITIES  
COMPOSITE YIELDS

CHARGE	SP.GR.	BBU/D	LV%	TONS/D	WT%	MSCFD
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
CHARGE		90000.0	100.00	14441.92	100.00	
PRODUCTS						
OCCIDENTAL SHALE OIL	.9165	90000.0	100.00	14441.92	100.00	
PRODUCTS		90000.0	100.00	14441.92	100.00	

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 USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED MATERIAL BALANCE  
 DUTY UNIT  
 COMPOSITE YIELDS

	SP. GR.	BBL/D	LVZ	TONS/D	WT%	HSCFD
CHARGE						
MIXED BUTANES	.5746	405.4	100.00	40.78	100.00	
CHARGE		405.4	100.00	40.78	100.00	
PRODUCTS						
MIXED BUTANES	.5743	405.6	100.05	40.78	100.00	
PRODUCTS		405.6	100.05	40.78	100.00	

## USAF SHALE OIL TO FUELS

## PHASE IV

CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

		DETAILED USAGE OF AN UNPOOLED UTILITY ELECTRIC POWER UNIT IS KWH COSTS ARE ALLOCATED TO PROCESS UNITS					PRICE IS .04500/UNIT			
PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D		
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1080	.673	9720.85	417.44		
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	1.9070	11.884	171627.72	7723.25		
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92829.0	14390.21	1.2677	8.160	117422.70	5284.02		
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	6.1047	41.622	518213.05	23319.59		
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05	.3912	3.464	4634.74	208.56		
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	.1399	1.301	1213.96	54.63		
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19	.1200	1.268	76.32	3.43		
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39						
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		21.974	2157.44	97.08		
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		211.850	151646.10	6824.07		
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE		345.31	.7065	5.296	1828.60	82.29		
UOP PLATFORING	COMBINED MODES	COMPOSITE USAGE	2588.2	345.13	2.3309	17.480	6032.93	271.48		
SOLR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	2588.3	3085.64	.3787	2.163	6674.09	300.33		
ARTINE REGENERATION	COMBINED MODES	COMPOSITE USAGE	17623.6	98.18		40.773	4003.15	180.14		
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88		3.393	936.01	42.12		
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13517.4	1985.51	.1638	1.136	2216.83	99.76		
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92						
DUTY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78						
TOTALS							998404.43	44928.20		

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USAF SHALE OIL TO FUELS  
PHASE IV

CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

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DETAILED USAGE OF A POOLED UTILITY  
600# STEAM UNIT IS MLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BSL/D	TONS/D	UNIT/BSL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0193	.120	1733.03	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	.0158	.102	1462.05	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11849.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		766.39				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		98.18	.220	.220	21.57	
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE		715.82	-6.694	-6.694	-6791.42	
LUP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31				
SOLAR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	2588.2	345.13				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64	-0.0603	-0.452	-155.97	
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	275.88				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	1985.51				
DUMMY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	14441.92				
				40.78				

TOTALS

-1730.74

AMOUNT PRODUCED FROM REFINERY FUELS

754.67 514.55

AMOUNT CONVERTED TO 150# STEAM

2485.62

## USAF SHALE OIL TO FUELS

## PHASE IV

CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF AN UNPOOLED UTILITY  
 COOLING WATER UNIT IS MGAL PRICE IS .03000/UNIT  
 COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	¢/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.0016	.010	145.86	4.38
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	.0263	.179	2228.43	64.86
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05	.0299	.264	353.91	10.62
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	.0116	.107	100.34	3.01
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19	.0857	.905	54.50	1.63
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		.535	382.75	11.48
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31	.0118	.089	30.66	.92
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	.0800	.600	207.08	6.21
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64	.1336	.763	2354.64	70.64
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		32.389	3180.00	95.40
AMONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88		10.961	3023.94	90.72
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51	.0200	.137	271.42	8.14
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUTTY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							12311.74	370.01

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USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
 REFINERY FUELS UNIT IS HBTU  
 COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	¢/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0218	.116	1961.21	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	.0482	.310	4466.72	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05	.1721	1.173	14609.37	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	.0640	.567	758.67	
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31	.0170	.62.082	44439.69	
UOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	.3096	.127	43.92	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3095.64		2.322	801.40	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18				
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13517.4	1985.51	.0486	.111	658.20	
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUTTY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							67319.19	

AMOUNT PRODUCED FROM F.O. STAB BOTTOMS

68425.25

AMOUNT CONVERTED TO 600# STEAM

686.07

## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
150# STEAM UNIT IS MLBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11648.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE		345.31				
LUP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.2	345.13				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	2588.3	3085.64				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE	17623.6	98.18				
ATTOMIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13517.4	1995.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUTY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							2485.42	
AMOUNT PRODUCED FROM 600# STEAM							2485.42	

Appendix B.8 (Cont.)

## UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

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## USAF SHALE OIL TO FUELS

## PHASE IV

## CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

DETAILED USAGE OF A POOLED UTILITY  
50% STEAM. UNIT IS MBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84898.1	12450.46	-0.117	-0.079	-989.81	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	.0460	.428	399.21	
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19	.0276	.292	17.55	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-9.864	-968.43	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31				
LOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13				
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		9.327	915.70	
ATTONTIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51				
COMBINED MODES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUTTY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							-625.78	
AMOUNT SOLD							625.78	.06

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, PSI.0  
 USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 4 - JP-8 JET FUEL + OF-2/DPH DIESEL

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DETAILED USAGE OF A POOLED UTILITY  
 BOILER WATER UNIT IS HLBS  
 COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21				
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46				
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05	.0390	.266	3314.31	
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE	635.4	60.19				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		766.39				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE		715.82	18.946	1860.15		
LOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31	19.391	13880.46		
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64	.0939	.706	242.94	
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	275.88				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	1985.51				
DUFFY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	14441.92				
TOTALS				40.78			19297.86	
AMOUNT PURCHASED							9824.12	4912.06
AMOUNT PRODUCED FROM CONDENSATE							9473.74	

UNIVERSAL OIL PRODUCTS CO. STANDARD OPTIMIZATION REPORTS, P51.0

USAF SHALE OIL TO FUELS  
PHASE IV

CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

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DETAILED USAGE OF A POOLED UTILITY  
CONDENSATE UNIT IS MILBS  
COSTS ARE ALLOCATED TO UTILITY POOL

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
H.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	-0.0193	-0.120	-1733.03	
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	-0.0158	-0.102	-1462.05	
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38	-0.0460	-0.428	-399.21	
DEPROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19	-0.0276	-0.292	-17.55	
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18		-0.684	-67.12	
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82				
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31				
LUP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	-0.0294	-0.221	-76.21	
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64	-0.2633	-1.504	-4619.86	
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		-10.987	-1078.72	
ANTONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.88				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1985.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUFFY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							-9473.74	

AMOUNT CONVERTED TO BOILER WATER

9473.74

## USAF SHALE OIL TO FUELS

## PHASE IV

CASE 4 - JF-8 JET FUEL + DF-2/DFM DIESEL

## DETAILED USAGE OF AN UNPOOLED UTILITY

CAT. &amp; CHEMICALS UNIT IS \$ PRICE IS 1.00000/UNIT

COSTS ARE ALLOCATED TO PROCESS UNITS

PROCESS UNIT	MODE	CONTROL STREAM	BBL/D	TONS/D	UNIT/BBL	UNIT/TON	UNITS/D	\$/D
FEED PREPARATION	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
L.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92	.1145	.714	10308.64	10308.64
M.P. HYDROTREATING	COMBINED MODES	COMPOSITE USAGE	92629.0	14390.21	.0417	.268	3858.02	3858.02
HYDROCRACKING	COMBINED MODES	COMPOSITE USAGE	84888.1	12450.46	.0578	.394	4910.46	4910.46
NAPHTHA SPLITTER	COMBINED MODES	COMPOSITE USAGE	11848.5	1338.05				
DEBUTANIZER	COMBINED MODES	COMPOSITE USAGE	8676.8	933.38				
D-PROPANIZER	COMBINED MODES	COMPOSITE USAGE	635.9	60.19				
FUEL GAS TREATER	COMBINED MODES	COMPOSITE USAGE		766.39				
SULFUR PLANT	COMBINED MODES	COMPOSITE USAGE		98.18				
HYDROGEN PLANT	COMBINED MODES	COMPOSITE USAGE		715.82		5.191	3715.56	3715.56
NAPHTHA HYDROTREATER	COMBINED MODES	COMPOSITE USAGE	2588.2	345.31	.0028	.021	7.36	7.36
LOP PLATFORMING	COMBINED MODES	COMPOSITE USAGE	2588.3	345.13	.0435	.326	112.55	112.55
SOUR WATER TREATING	COMBINED MODES	COMPOSITE USAGE	17623.6	3085.64				
AMINE REGENERATION	COMBINED MODES	COMPOSITE USAGE		98.18		.283	27.75	27.75
ATFONIA PLANT	COMBINED MODES	COMPOSITE USAGE		275.89				
FUEL OIL STABILIZER	COMBINED MODES	COMPOSITE USAGE	13537.4	1935.51				
COMBINED FACILITIES	COMBINED MODES	COMPOSITE USAGE	90000.0	14441.92				
DUTTY UNIT	COMBINED MODES	COMPOSITE USAGE	405.4	40.78				
TOTALS							22940.11	22940.11

USAF SHALE OIL TO FUELS  
 PHASE IV  
 CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	ELECTRIC POWER KWH	600# STE AM HLBS	COOLING WATER MGAL	REFINERY FUELS MMBTU	150# STE AM HLBS	50# STE AM HLBS	BOILER W ATER HLBS	CONDENSA TE HLBS
FEED PREPARATION	9720.9							
L.P. HYDROTREATING	171627.7	1713.0	145.9	1961.2				-1733.0
H.P. HYDROTREATING	117422.7	1462.0		4466.7				-1462.0
HYDROCRACKING	518213.0		2228.6	14609.4	-1573.7	-989.8	3116.3	
NAPHTHA SPLITTER	4634.7		353.9	758.7				
DEBUTANIZER	1214.0		100.3			399.2		-399.2
SULFUR PLANT	76.3		54.5			17.6		-17.6
HYDROGEN PLANT	2157.4	21.6			-745.5	-968.4	1860.1	-67.1
NAPHTHA HYDROTREATER	151646.1	-4791.4	382.8	44439.7			13880.5	
UOP PLATFORMING	1828.6		30.7	43.9				
SOUR WATER TREATING	6032.9	-156.0	207.1	801.4			242.9	-76.2
AMINE REGENERATION	6674.1		2354.6		1.8			-4639.9
ANTONIA PLANT	4003.2		3180.0		4639.9			-1078.7
FUEL OIL STABILIZER	936.0		3023.9		163.0	915.7		
	2216.8		271.4	658.2				
TOTAL CONSUMPTION	998404.5	-1730.7	12333.7	67739.2	2485.4	-625.8	19297.9	-9473.7

## USAF SHALE OIL TO FUELS

## PHASE IV

CASE 4 - JP-8 JET FUEL + DF-2/DFM DIESEL

## PROCESS UNIT UTILITY CONSUMPTION SUMMARY

PROCESS UNIT	CAT. & C HEMICALS
FEED PREPARATION	
L.P. HYDROTREATING	10308.6
H.P. HYDROTREATING	3858.0
HYDROCRACKING	4910.5
NAPHTHA SPLITTER	
DEBUTANIZER	
DEPROPANIZER	
SULFUR PLANT	
HYDROGEN PLANT	3715.6
NAPHTHA HYDROTREATER	7.4
UOP PLATFORMING	112.5
SOUR WATER TREATING	
AMINE REGENERATION	27.7
AMONIA PLANT	
FUEL OIL STABILIZER	
TOTAL CONSUMPTION	22940.3

Appendix B.8 (Cont.)

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